nationalgrid

Stage 05: Draft CUSC Modification Report

- Volume 3

Connection and Use of System Code (CUSC)

CMP213 Project TransmiT TNUoS Developments

Consultation responses

Published on: 22nd May 2013

What stage is this document at?

01	Initial Written Assessment
02	Workgroup Consultation
03	Workgroup Report
04	Code Administrator Consultation
05	Draft CUSC Modification Report
06	Final CUSC Modification Report

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About this document

This document contains the responses to the Workgroup consultation which took place between 07 December 2012 and 15 January 2013 and the Code Administrator consultation which took place between 10 April 2013 and 9 May 2013.

Document Control

Version	Date	Author	Change Reference
1.0	22 May 2013	Code Administrator	Publication to Panel

Any Questions?

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1. Workgroup Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	*Marc Murray* *e-mail: marc.murray@aquamarinepower.com* *phone: 0131 524 1431*
Company Name:	*Aquamarine Power*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	*Aquamarine Power is the technology developer of the Oyster Wave Power technology, which captures energy from near shore waves and converts it into clean sustainable electricity. A Scottish company, based in Edinburgh, we were established in 2005 with a clear mission; to make marine renewable energy mainstream through rapid and responsible commercialisation of the Oyster wave energy converter technology.* *Aquamarine Power has secured to date, through its associated development company Lewis Wave Power and its Brough Head Wave Farm Ltd development partner SSE Renewables, grid capacity of over 240MW for a number of projects based on the Scottish Islands. In common with the majority of planned projects (>95%) in the nascent wave industry, cost competitive and viable island connections are intrinsic to establishing the long term potential of this emergent new source of reliable renewable energy.* *We believe that the CMP 213 objectives of competition, cost reflectivity and reflecting transmission developments has been too narrowly interpreted by the working group and fails to*

	address some of the key challenges facing the emergent wave industry and more generally the Scottish Islands; specifically: • *The narrow interpretation of competition fails to take into account how the actions proposed by the workgroup in both the original and amended versions will impact competition between various forms of electrical generation technologies. Both the original and amended proposals create an artificially high barrier to entry to the UK energy market for wave technologies. Fundamentally the proposals are handing an unfair competitive advantage to other generation technologies which are not locational dependent.* • *Cost reflectivity has been too loosely applied when considering island technologies to "normal" onshore connections, with island connections facing localised charges that would not be charged for an onshore connection. Again artificially raising the barrier to entry for island developments, including wave technologies. There need to be comparable treatment with wider assets. At the very minimum we agree with the suggestion that HVDC connection costs should be treated in the same manner as AC connections (i.e. removal of the HVDC elements that are not included in the locational signal for an AC transmission network)* • *In terms of reflecting transmission developments, the Scottish Islands have been categorised or treated the same as an offshore wind development (as they both need HVDC connections). We believe that this is unwarranted and that the charging arrangements for the Scottish Islands should be considered separately to the offshore connections. The Scottish Islands need to be treated as the exception to the rule, taking into account their special circumstances. The islands should be treated as a strategic asset that requires a connection solution that encourages renewable connections on the islands, rather than creating a barrier to development. The distinct message is that the CMP 213 has failed to find a solution to the Scottish Island connection issue; instead the proposals more generally raise the barrier to achieving a sustainable solution to connecting the islands.* • *Finally we believe that other fundamental considerations should have been taken into account, such as security of supply and sustainability, which, although key criteria for both National Grid and Ofgem, have been given much less weighting than the heavy focus on locational cost reflectivity. A long term cost effective solution needs to be identified for the islands (without reliance on temporary support*

	mechanisms such as ROCs or capping), which the workgroup has failed to address.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*As stated before we believe that both proposals are inadequate to address the Scottish Islands solution; specifically:* *(a) Both methodologies present an artificial barrier to wave technologies to effectively compete within the UK generation market, with the resultant effect of reducing the UK's security of supply.* *(b) The locational element in both charging methodologies has effectively "double accounted" transmission assets for island connections – effectively over charging on locational elements – we disagree with the over emphasis on locational charging and specifically seek more elements of the islands connections to be socialised (recognising it as a national asset, rather than a company asset which an offshore connection would be)*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	*For the Scottish Islands elements, we do not support either approach. Instead a more fundamental solution to the Scottish Islands connections needs to be implemented, including the consideration of socialising the HVDC connection as part of the wider UK asset infrastructure (i.e. being the exception to the rule that treat connections beyond the nearest MITS station as local works)*

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	*No, we believe that the scope of the review was too narrowly interpreted by the workgroup. In essence all that was considered was how Scottish renewable and English base loads interacted, failing to address/ investigate the impact of diversity of generation types. The amended version effectively heightens the barrier to Scottish Island connections.* *In addition the ability of different generation technologies being able to share the same transmission infrastructure (e.g. wave and wind) based on the intermittency of the generation characteristics needs to be considered (particularly on the local island networks).*

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*As question 1*
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	*No, we believe that:* • *Further consideration is required on the sharing between different generation types (e.g. counter correlation between wave and wind) as suggested by ICIT.* • *More detailed consideration of terming the Islands as MITS for charging purposes to present a more cost effective solution.* • *Consideration of socialising the HVDC connection as part of the wider UK asset infrastructure (i.e. being the exception to the rule that treat connections beyond the nearest MITS station as local works)*

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	• *Whilst it is accepted that the investment cost would be higher, the outcome should not be that TNUoS charges for the island are 10 times their nearest neighbours (as in the case of Lewis and Skye). We believe that an alternative focus for island connection is required, rather than a one size fits all methodology. The most sustainable solution would be to make the island connections as the exception to the rule, rather than being reliant on external temporary imposed solution (such as additional island ROCs or capping).*
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	*We disagree with the suggestion that the Scottish Islands should be treated the same as an offshore wind development (as they both need HVDC connections). The charging arrangements for the Scottish Islands should be considered separately to the offshore connections. The Scottish Islands need to be treated as the exception to the rule, taking into account their special circumstances. The islands should be treated as a strategic asset that requires a connection solution that encourages renewable connections.* *At the very minimum we agree that Island HVDC connection costs should be treated in the same manner as AC connections (i.e. removal of the HVDC elements that are not included in the locational signal for an AC transmission network)*
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	*Fundamentally we believe that the either changing the charging definition of Local and Wider, or treating the connections to the Scottish Islands as MITS for charging purposes. This is the only way to ensure that this UK strategic asset is realised. Arguments such as security of supply and sustainability alone make this a reasonable suggestion.*

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*A stated before further work is needed on the capacity for sharing amongst intermittent generation technologies and counter correlation (in line with the ICIT work)* *We would also ask that the workgroup look at a wider definition of the narrow interpretation of the remit to ensure that other factors beyond locational charging is examined; to ensure that the full benefit on the basis of competition, security of supply and sustainability is achieved.*
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	• *Fundamentally the review has failed to achieve clarity on island charging or provide a long term sustainable solution to connecting the generation capacity of the Scottish Island renewable resource; in particular the vast majority of the available UK wave resource.* • *The outcome of the TNUoS review should not significantly disadvantage the islands to any other part of the UK mainland. Whilst it is accepted that the investment cost would be higher, the TNUoS charges for the island should not be 10 times their nearest neighbours (as in the case of Lewis and Skye). A sensible outcome needs to be achieved. This has to be the focus for island connections, rather than focussing on one size fits all methodology. It needs to be accepted that the only sustainable solution is to make the island connections as the exception to the rule, rather than being reliant on external temporary imposed solution (such as additional island ROCs or capping).* • *At a very minimum, where island conform to the definition of Wider, they should be treated in the same way as any other part of the onshore network.* • *Island links , where they are radial HVDC should be as a minimum be treated in the same way as parallel “bootstrap” links as far as expansion factors are calculated* • *A security factor of 1 (whether is it’s classified as wider or local) should be used for links where there is no redundancy.*

Q	Question	Response
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	*We believe that clarity is very important for the industry. We suggest that finalisation of the general arrangements are as soon as possible; however ensuring that the door is left open to find a systemic solution for island connections that does not significantly disadvantage the islands to any other part of the UK mainland.*
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	-
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	
Do you have any other comments?		

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	Ricky Hill (ricky.hill@centrica.com)
Company Name:	Centrica
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Centrica welcomes this consultation and the work undertaken by the working group to develop the CMP213 proposals. Nevertheless, we believe that there would have been merit in publishing the consultation at a later date when the potential alternatives on sharing have been further developed to a level where parties are better able to assess the impact on charges. On the back of this Users (especially non–workgroup parties) would be more able to comment on the direction and suitability of alternatives. We believe that a key issue is the compressed timescales of the CUSC process. Indeed, it seems that timescales are the key driver of this process and that there is a risk that the group will arrive at a sub-optimal conclusion and / or that group will not have sufficient time to fully work up the alternatives for the code administration consultation. This would evidently be a sub-optimal outcome and could delay the process further. In the light of this we ask that workgroup review the current work plan and request an extension on the timescales if required. We also believe that it would be helpful to get feedback from Ofgem on whether they have any concerns or foresee any issues with the work being undertaken by the group.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	**No**. In particular, we believe that the original would not better achieve CUSC objectives a) and b): the effective competition in the generation and supply of electricity and the production of charges which reflect, as far as is reasonably practicable, the costs incurred by transmission licensees. The proposed original would lead significant financial transfers between parties without robust justification. We believe that the

	analysis developed through the Working Group, Centrica and work we commissioned from Bath University[1] has demonstrated that many of the key arguments of the proposals are flawed. The CMP213 original is founded on the proposer's conclusion (using analysis from the ELSI model) that a generator's annual load factor shows a high degree of linearity with incremental constraint costs, accepting that this relationship breakdown over time. The evidence which is used to demonstrate this linearity is typically based on a 2011/12 generation background (inc. that on pages 176 to 179 of the workgroup consultation document). Analysis undertaken by Centrica using the ELSI model using 2015/16 input data (including boundary capacity data from the Seven Year Statement) show no distinguishable linearity between load factor and constraint costs in the majority of zones (please see the annex). Examining the relationship between load factor and incremental constraint costs the ELSI model produces on a 2015/16 background is important because it is, for obvious reasons, a more relevant time period than 2011/12. The breakdown of any perceivable relationship by 2015 should be examined by the Working Group. We have sought to further research whether load factor is a key driver of incremental constraint costs and whether the original could result in cost reflective charges. The study we commissioned from Bath University demonstrates that the relationship between congestion cost and load factor is far from linear and that congestion costs depend on network location, the network characteristics, the characteristics of the generation and the profile of demand. The Redpoint modelling undertaken in 2011 demonstrated that the Improved ICRP original would have £1.4 billion predicted impact on consumers' bills to 2030 relative to the status quo whilst at the same time providing minimal benefit to the deployment of renewables. These increases in costs to consumers seem incongruent with the current environment of consumers being financially squeezed and subsequent regulatory measures being taken to reduce costs. It also sits ill at ease with Ofgem's first priority which is protecting existing and future customers. We do not believe that the original properly takes account of the developments in transmission licensees' transmission businesses, and in particular the way in which it interprets the "dual criteria" changes to the SQSS as a "dual background" in charging. For example, CMP213 uses peak demand to bin both 'peak' and 'year-round' which does not seem appropriate with respect to the calculation of the latter tariff. The 'year-round' tariffs is supposed to reflect the second criterion in the GSR009 changes which introduce an economy criterion that requires that

[1] We commissioned the University of Bath to examine the drivers of year-round system congestion costs in the light of CMP213. We intend to circulate the report to the group shortly.

	sufficient transmission system capacity be provided to accommodate all types of generation in order to meet varying levels of demand efficiently. In summary, we do not believe that the dual tariff results in an incremental signal that is meaningful or accurately replicates the aims of the SQSS changes undertaken through GSR009.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	Whilst we do not support CMP213 as it stands, option 4 (April 2015) is in our view the most appropriate date for implementation. The technical feasibility of an April 2014 implementation is wholly dependent on strict deadlines being met. In addition, assuming April 2014 is technically possible, it does not provide generators with sufficient foresight to react to the change in signal. This could partially be overcome by reducing the required notice period to amend TEC levels, but it would not provide sufficient notice to generators to deal with other issues including site closures with associated redundancies and the unwinding of power purchase contracts.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	We believe that the Workgroup has adequately set out and considered all relevant options, subject to a slight alternation to method 3. We believe that the analysis undertaken by the working group shows that the proposed linearity between load factor and constraint costs within the Original is found wanting particularly in areas dominated by one type of generation. Given that the network will increasingly have areas dominated by one generation type, which will further reduce the proposed linear relationship between load factor and constraint costs, we believe that in order for any new charging methodology to be credible and future-proof, it is essential that an alterative be developed that takes diversity of generation into account. Of the three potential alternatives to sharing outlined on page 52 of the consultation, our current view is that method 3, subject to a small amendment described below, has the most potential to overcome the inadequacies of the Original. This is because as well as taking into account of generation diversity, it would also be calculated on a single background. As noted above, Centrica does not believe that splitting the TNUoS tariff into peak and year-round will result in an incremental signal that is meaningful as it distorts the aims of the NETSQSS changes to which it is associated. We propose amending method 3 such that the assumed level

Q	Question	Response
		of sharing is not capped at an arbitrary 50% (currently, of the proposed alternatives, only method 1 does not arbitrarily cap the level of sharing at 50%). Capping the amount of deemed sharing at a maximum 50% based on the fact that “maximum sharing occurs when a TNUoS zone contains an equal capacity of both low carbon and carbon generation and that the optimum transmission boundary capacity would be 50% of the combined capacities” is flawed. We can assume a case where two 100MW generators (G1 ad G2) are sharing a 100MW transmission asset. G1 is running at full capacity and G2 is turned off and they then swap, such that G1 is turned off and G2 is running at full capacity. It is evident that 100% sharing has taken place. In summary, we believe that a method 3 which is modified in this way is likely to lead to more cost-reflective and justifiable changes to Users’ tariffs than that proposed in the Original. We would ask the working group to vote on taking this forward as an alternative and note our recent informal conversation with National Grid outlining out intention to propose this in this manner.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	We think that the options on how a sharing factor (i.e. ALF) could be calculated have been sufficiently reviewed. However, with regards to the option whereby ALF would be calculated on a 5-year historic basis, we would ask the Working Group to review the case to reduce this to 3 years. Whilst we accept that analysis described in Annex 9 which shows little difference between an ALF based on 3 years previous data or 5 years previous data, we believe that given the significant changes occurring on the system, in particular with gas plant being out of merit and entering into STOR contracts, a 3 year historic ALF could be much more represented of future load factor.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	We do not have a strong view whether intermittent generation should be exposed to the peak element of the TNUoS tariff. This is because we fundamentally disagree that the methodology for deriving the peak tariff either accurately replicates the objectives of the SQSS GSR009 change or provides a meaningful signal.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We believe all the high-level potential options for sharing which are relevant to this modification proposal have been considered. This is subject to our response to question 1 where we stated that we propose amending method 3 such that the assumed level of sharing is not capped at an arbitrary 50%. We do, however, believe that that potential alternatives should have been more adequately set out in terms of explaining their likely impact on tariffs relative to the Original. We believe that there would have been merit in publishing the consultation at a later date when the alternatives on sharing have been further developed, in particular with regards to the associated impact on charges. This would enable parties (especially non – workgroup parties) to better comment on the direction and suitability of alternatives.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	Our current initial view is that in the in the absence of a model with multiple backgrounds, which is unlikely to be practical in the context of CMP213, the current ICRP methodology calculated on a single background would seem to best reflect the differential impact of generators on incremental network costs. Nevertheless, we encourage the development of alternatives which build on the CMP213 original to take into account generator diversity as well as load factor and will judge these on their own merit. We do not believe that CMP213 original would be an accurate reflection of generators' impact on incremental network costs. As the workgroup has discussed, and Bath University work has demonstrated, while load factor is a measure of an average output of a generation technology over the year, the cost of congestion varies between locations and changes in its intensity, time, and duration throughout the year which is not represented in CMP213 original. Rather, the use of a single year-round scenario and load factor to reflect year-round congestion costs essentially assumes that all boundaries have the same level of congestion throughout of the year which has been proven to not be the case. In theory, a more cost reflective TNUoS charge would relate the charges with times and boundaries when congestions are most severe by introducing a time of use element to the existing peak security based TNUoS charges. This would expand the present year-round scenario to a number of scenarios that are directly linked to congestion times and boundaries. This would essentially equate to a market model. However, as the TAR process has shown, it is extremely difficult for generators to provide the requisite information to make this viable, at least on an ex-ante basis.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes, at the current time we believe that all relevant options have been considered.

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	Centrica believes that HVDC circuits should be incorporated into charging methodology in a way which most accurately reflects the associated costs and is consistent with the rest of the charging methodology. In this respect we believe that 100% of the cost of the sub-sea cables should be included in the expansion factor. However, with regard to the converter stations, we believe that there may be merit in removing those elements that are similar to the AC transmission network. Should such an approach be implemented we believe that it should also be replicated in the methodology for offshore links. In terms of calculating the flows on HVDC links we note that the calculation of impedance is not an exact science due to its controllable nature and that a reasonable proxy needs to be developed. We currently support the methodology set out in the original proposal which would calculate the base case flow down the HVDC transmission circuit as a ratio of power flows to circuit ratings across a transmission network boundary ‘crossed’ by the HVDC circuit. We believe this to be a pragmatic approach to a calculation that is ultimately subjective. We note that the Working Group discussed a potential alternative which would calculate the base case flows on the single most constrained transmission boundary that the HVDC circuit reinforces. However, we did not entirely understand the justification for this approach and would welcome further clarity in this area.

Q	Question	Response
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes, at the current time we believe that all relevant options have been considered.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes, at the current time we believe that all relevant options have been considered.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	At the current time we believe that the principles set out in the Original generally offer the best. This is of course subject to our serious concerns about the sharing proposals that we outline in our response to questions 1 to 5. In line with the original, we do not believe that there in a requirement to change the definition of a MITS node. Furthermore, as the workgroup has noted, and because of zoning and the specific expansion the island generation tariff for an island link classed as local or wider is likely to be very similar. As a supporter of cost reflectivity in transmission charges, we believe the approach set out in the Original whereby new expansion factors would be calculated for each type of transmission technology and the locational security factor would be adjusted to reflect redundancy provided on the link offers the best solution at the current time. In terms of the different expansion factors to be calculated for each type of technology, we would support this being undertaken on to a high level of granularity such that the principle of cost reflectivity is followed as robustly as possible. In line with our response to question 9, we believe that with regard to converter stations for HVDC island links, there may be merit in removing from the expansion factor those elements that are similar to elements of the AC transmission network HVDC.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	Whilst we do not support CMP213 as it stands, option 4 (April 2015) is the most appropriate date for implementation. The technical feasibility of an April 2014 implementation is wholly dependent on strict deadlines being met. In addition, assuming April 2014 is technically possible, it does not provide generators with sufficient foresight to react to the change in signal. This could partially be overcome by reducing the usual required notice period to amend TEC levels, but it would not provide sufficient notice to generators to deal with other issues including site closures with associated redundancies and the unwinding of power purchase contracts.

Q	Question	Response
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Please see response to question 16.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	Yes, please see response to question 1
Do you have any other comments?		We commissioned the University of Bath to examine the drivers of year-round system congestion costs in the light of CMP213. We intend to circulate the report to the group shortly.

Annex - the linearity of the relationship between load factor and incremental constraint costs

Introduction

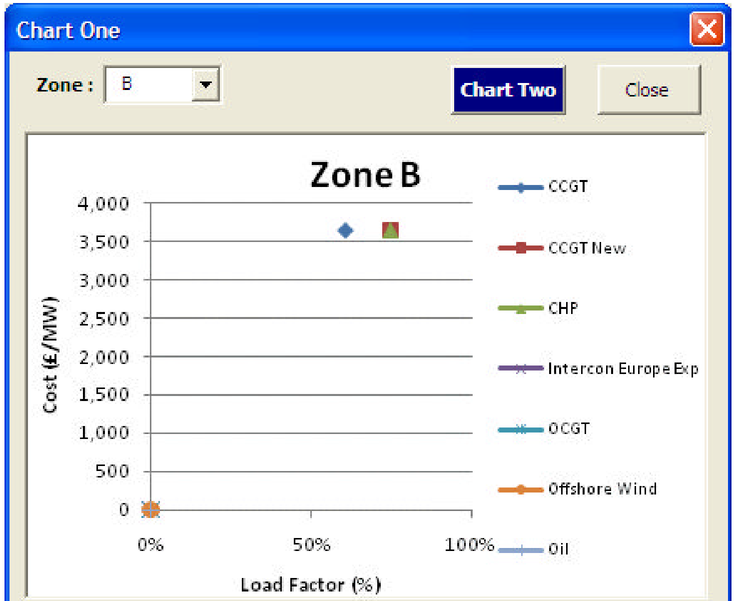
- The purpose of these slides is to illustrate some of the work done using the ELSI model to view how the linearity between load factor and incremental constraint costs changes over time. Each of the zones was modelled for both 2011/12 and 2015/16 but for the purposes of this annex we have just included a selection for illustrative purposes. We are happy to present all of the analysis to the work group.

- For the analysis we used ELSI version 4 circulated on 28th August 2012. We have used a gone green generator scenario, scaling and prices. We have used the 2011 National Grid Seven year Statement to input 2015/16 boundary capacities.

- Based on the above assumptions, in most zones, there is no perceivable linearity between incremental constraint costs and load factor by 2015/16. This also true of zone Z (northern Scotland) which sees the amount of wind generation increase from 850MW to 2010MW over the period. In zone R, where a strong level of linearity is maintained , there is a relatively high level of generation diversity.

Zone B

2011/12



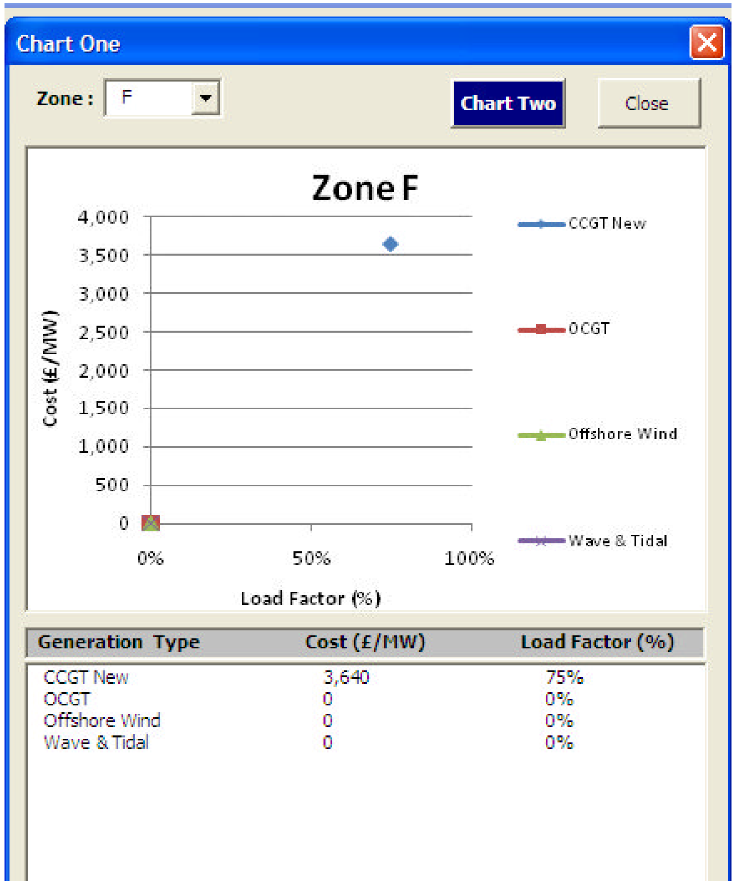
Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	3,640	61%
CCGT New	3,640	75%
CHP	3,640	75%
Intercon Europe Exp	0	0%
OCGT	0	0%
Offshore Wind	0	0%
Oil	0	0%

2015/16

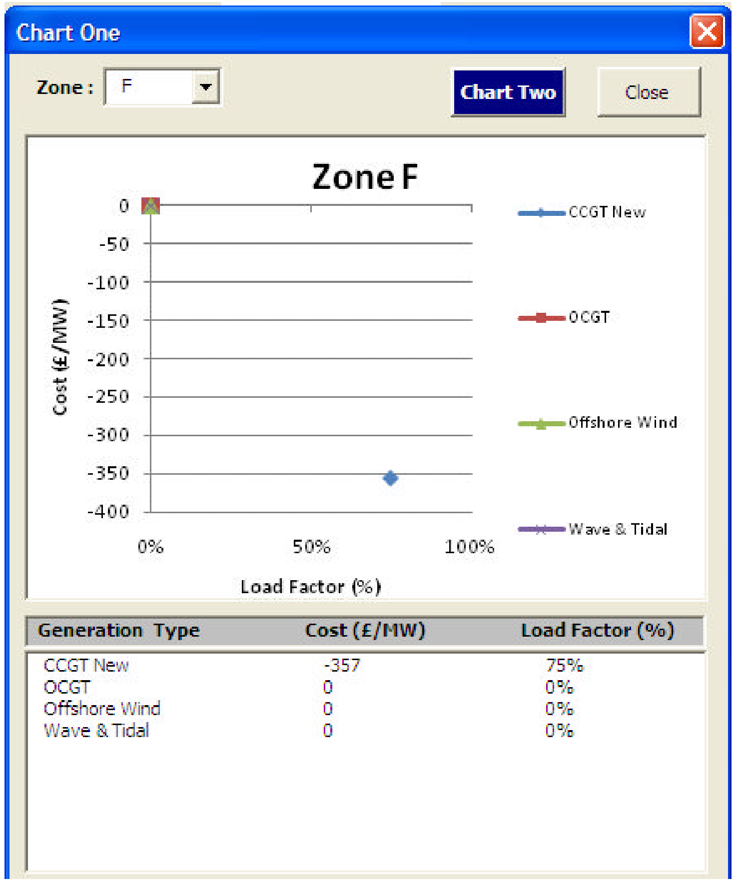
Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	-357	46%
CCGT New	-357	75%
CHP	-357	75%
Intercon Europe Exp	0	0%
OCGT	0	0%
Offshore Wind	0	0%
Oil	0	0%

Zone F

2011/12

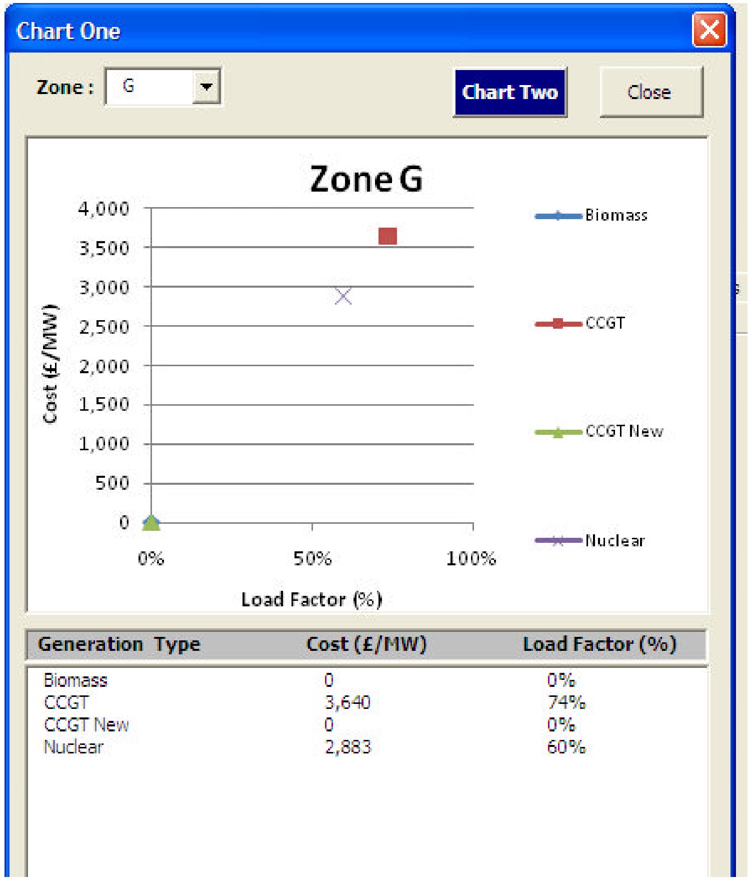


2015/16



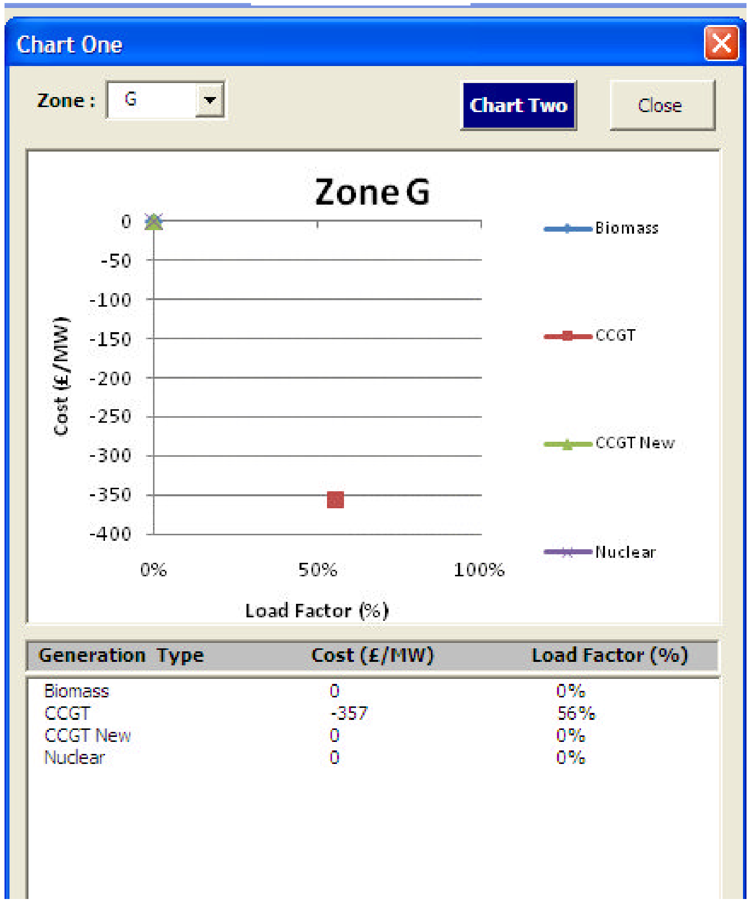
Zone G

2011/12



Generation Type	Cost (£/MW)	Load Factor (%)
Biomass	0	0%
CCGT	3,640	74%
CCGT New	0	0%
Nuclear	2,883	60%

2015/16



Generation Type	Cost (£/MW)	Load Factor (%)
Biomass	0	0%
CCGT	-357	56%
CCGT New	0	0%
Nuclear	0	0%

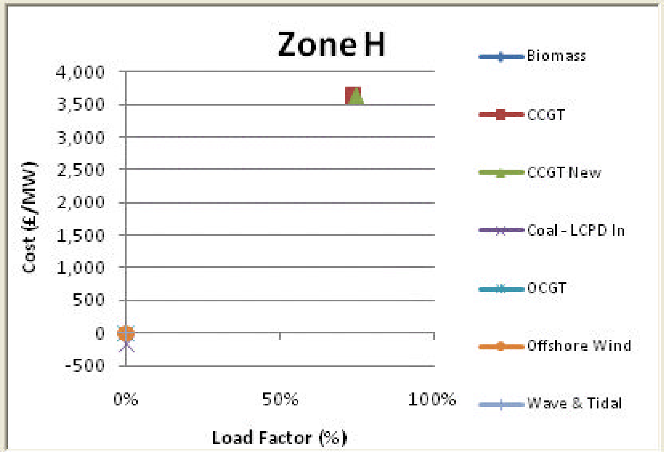
Zone H

2011/12

Chart One

Zone : H

Chart Two | Close



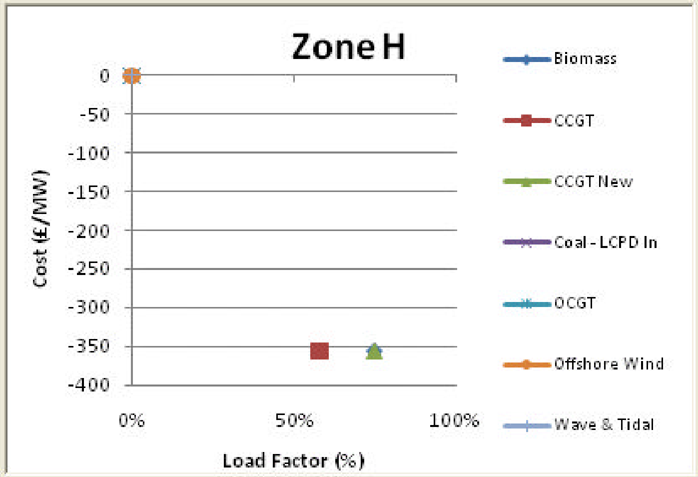
Generation Type	Cost (£/MW)	Load Factor (%)
Biomass	0	0%
CCGT	3,640	74%
CCGT New	3,640	75%
Coal - LCPD In	-163	1%
OCGT	0	0%
Offshore Wind	0	0%
Wave & Tidal	0	0%

2015/16

Chart One

Zone : H

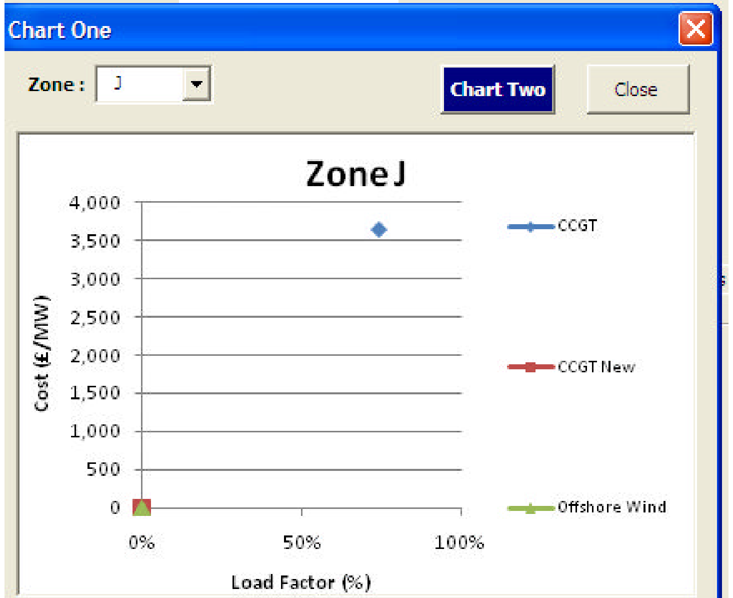
Chart Two | Close



Generation Type	Cost (£/MW)	Load Factor (%)
Biomass	-357	75%
CCGT	-357	58%
CCGT New	-357	75%
Coal - LCPD In	0	0%
OCGT	0	0%
Offshore Wind	0	0%
Wave & Tidal	0	0%

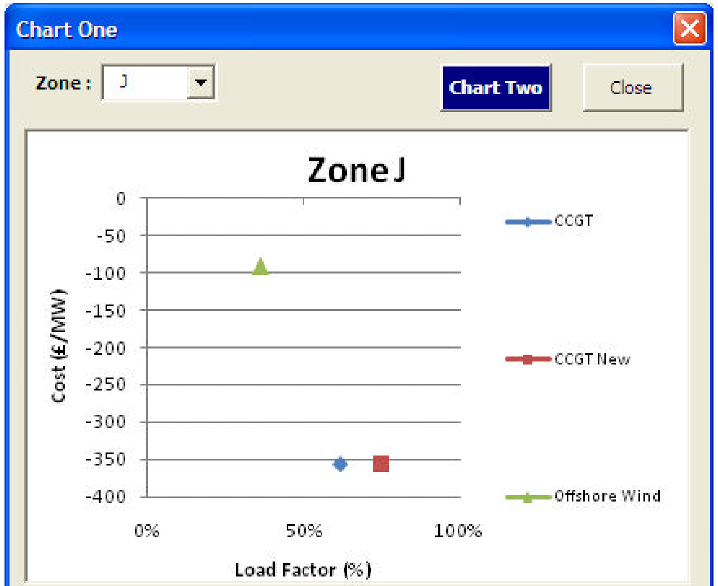
Zone J

2011/12



Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	3,640	74%
CCGT New	0	0%
Offshore Wind	0	0%

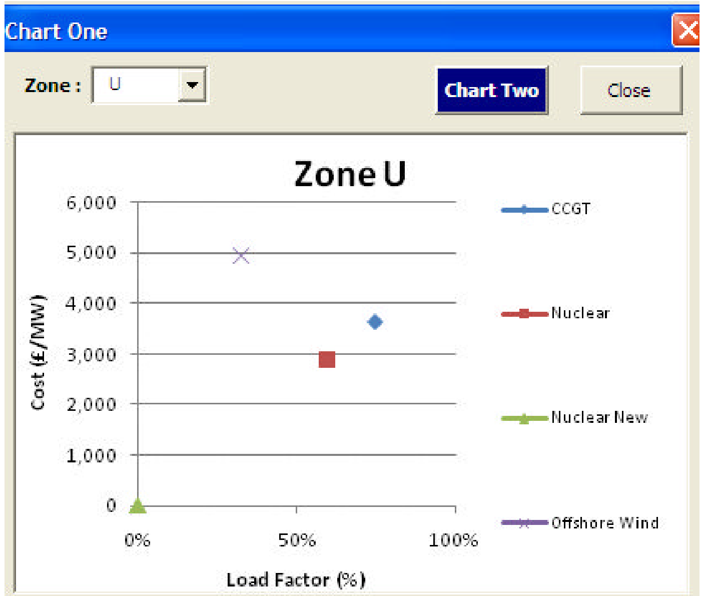
2015/16



Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	-357	62%
CCGT New	-357	75%
Offshore Wind	-91	36%

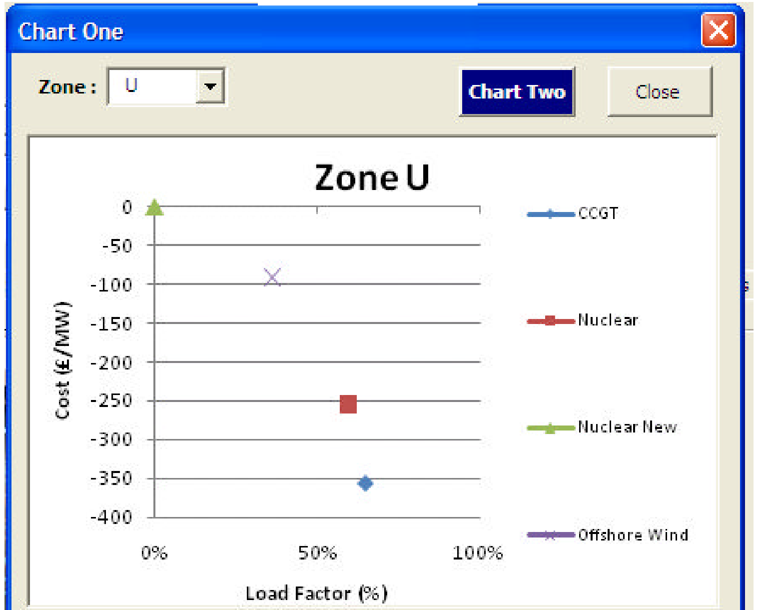
Zone U

2011/12



Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	3,640	75%
Nuclear	2,883	60%
Nuclear New	0	0%
Offshore Wind	4,944	33%

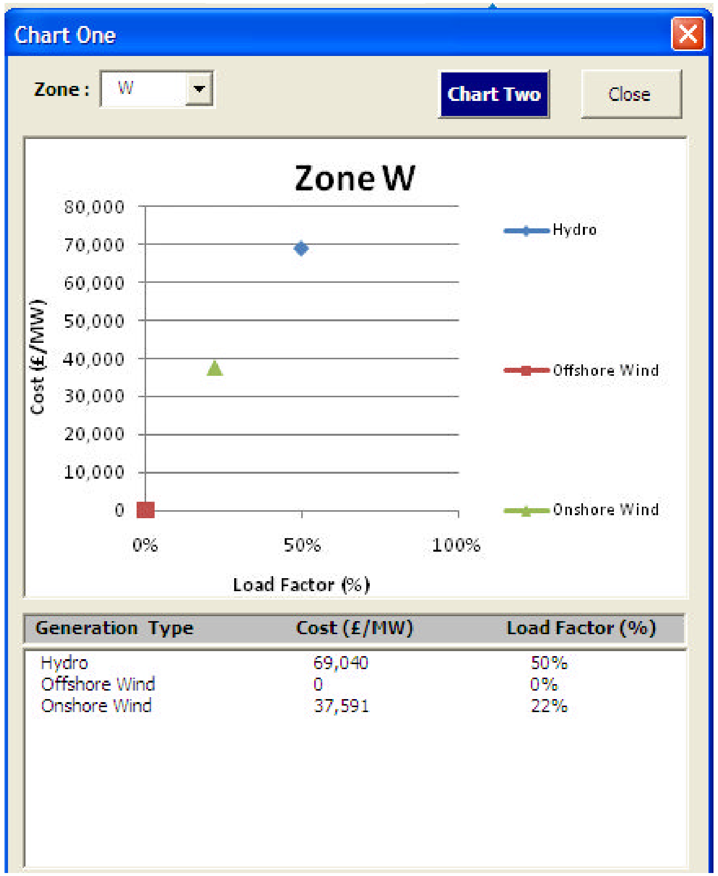
2015/16



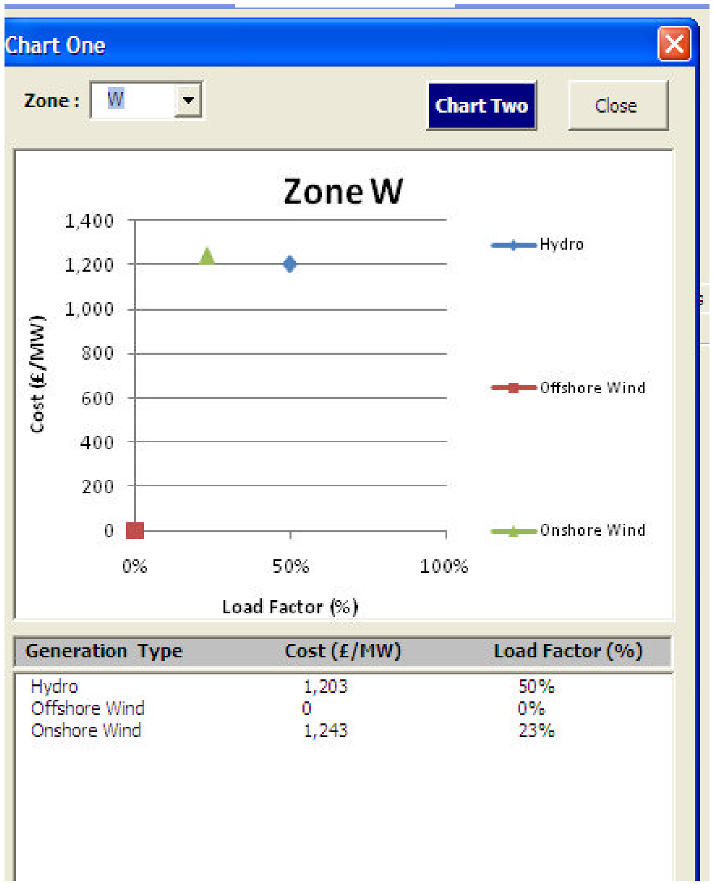
Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	-357	65%
Nuclear	-255	60%
Nuclear New	0	0%
Offshore Wind	-91	36%

Zone W

2011/12

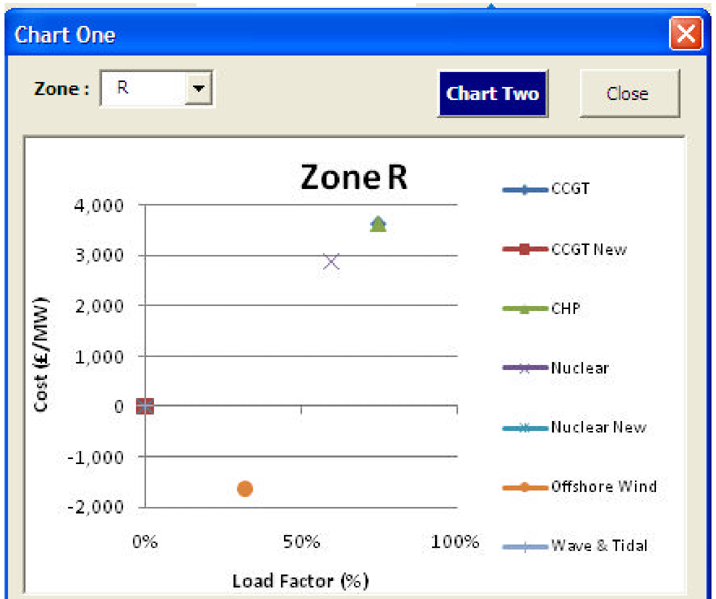


2015/16



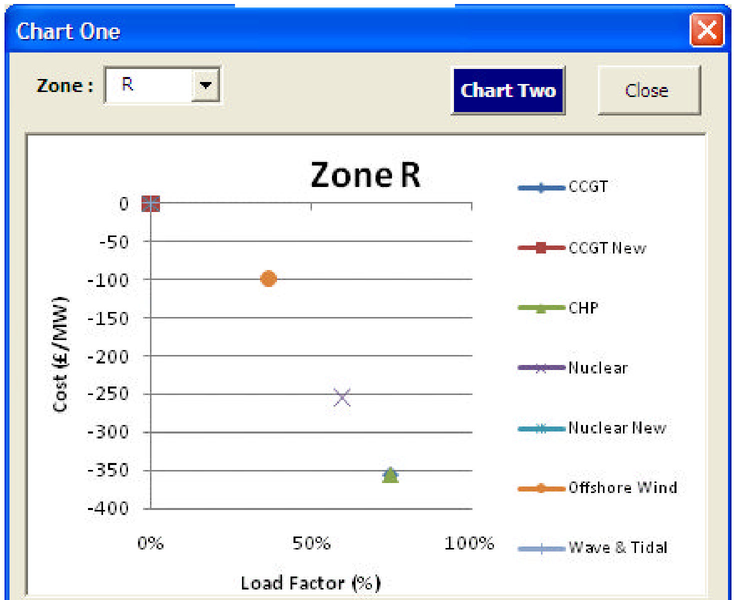
Zone R

2011/12



Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	3,640	75%
CCGT New	0	0%
CHP	3,640	75%
Nuclear	2,883	60%
Nuclear New	0	0%
Offshore Wind	-1,638	32%
Wave & Tidal	0	0%

2015/16



Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	-357	75%
CCGT New	0	0%
CHP	-357	75%
Nuclear	-255	60%
Nuclear New	0	0%
Offshore Wind	-99	37%
Wave & Tidal	0	0%

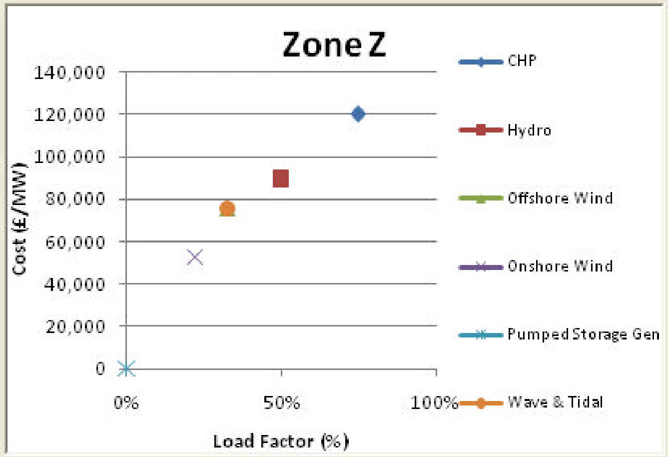
Zone Z

2011/12

Chart One

Zone : Z

Chart Two | Close



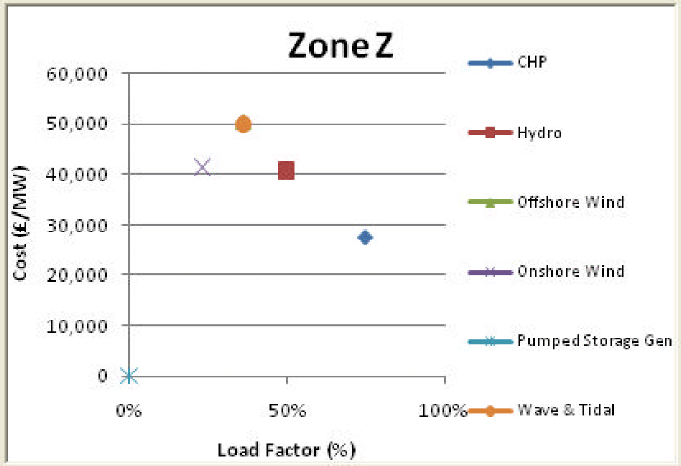
Generation Type	Cost (£/MW)	Load Factor (%)
CHP	120,364	75%
Hydro	89,708	50%
Offshore Wind	75,906	33%
Onshore Wind	52,510	22%
Pumped Storage Gen	0	0%
Wave & Tidal	75,906	33%

2015/16

Chart One

Zone : Z

Chart Two | Close



Generation Type	Cost (£/MW)	Load Factor (%)
CHP	27,514	75%
Hydro	40,798	50%
Offshore Wind	50,325	36%
Onshore Wind	41,448	23%
Pumped Storage Gen	0	0%
Wave & Tidal	49,914	36%

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RE: CMP213 Project TransmiT TNUoS Developments

15 January 2013

Our ref. 130115_CMP213

Danielle Lane
dlane@dongenergy.co.uk
Tel 02078115200

Thank you for the opportunity to comment on the work carried out by the CMP213 working group. DONG Energy is a leading energy company operating in Northern Europe and headquartered in Denmark. It is one of the most active offshore wind operators and investors in the United Kingdom. We operate 700 MW of offshore wind farms, and have approximately 1.2 GW under construction and a strong pipeline of future projects. In addition to our offshore wind farms, we own and operate a 824 MW CCGT plant in Wales.

The working group has done a good job in carrying out a comprehensive review, and we do not believe that further issues should be considered at this time. Subject to the commercial consequences of the original proposal, we believe this is broadly the right option for the working group to look at.

Sharing

We believe the core principles have been addressed for the sharing issue, and support the link between the SQSS planning statement and the proposed changes to TNUoS charges. We further believe there is merit in investigating the diversity issue further, but within the scope already set out by the report. We recognise that there is a potential conflict between the cost reflectivity and simplicity and transparency of the potential sharing with diversity options, but do not believe that the options as presented in the work group report have been developed to a sufficient stage for us to comment on in more detail.

However, as TNUoS charges have large commercial implications for generators, we further believe stakeholders should be given sight of the possible changes to tariffs and be given an opportunity to comment further on the proposals with this information in mind.

HVDC Circuits

We remain uncertain as to why the original proposal has chosen to treat HVDC circuits as a pseudo-AC technology in one instance, and as a technology

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London EC2Y 9UE, United Kingdom

completely separate from AC in another: the proposal to on the one hand model the load flow component as AC, but treat the expansion factor as DC is not consistent. While incorporating a new technology into the models used by National Grid is not simple, we believe it has to be done in a consistent manner.

We are thus uneasy as to the treatment of HVDC, on one hand, as a pseudo AC circuit in determining flows on the system, but as a HVDC link with no socialisation of costs when calculating expansion factors on the other. HVAC substation equipment is not locationally charged, and we would be interested to see what proportion of the regulated asset base is made up of these types of assets. The HVDC solution for west coast reinforcement was chosen not only based upon the ability to deliver the necessary reinforcement in a timely manner, but also on a cost benefit when considering CAPEX and OPEX (system losses) against a 400kV onshore solution. If a solution represents the cheapest option for reinforcing the system, we do not believe it should it be charged at a premium.

The option of including the converter stations in the circuit expansion factor would result in a negative impact on competition: for a similar capital cost as an AC link (although we recognise that in the case of the bootstraps onshore AC reinforcement is deemed not possible in the timescales required), the DC link would result in significantly higher TNUoS charges for some generators. It does not seem reasonable that certain generators should be negatively impacted based on the technology choice of the TO, when the CAPEX costs are so similar.

It may be possible to calculate an expansion factor for a HVDC investment by multiplying the overall HVDC CAPEX by the ratio of line to substation assets in the remainder of the onshore RAV, thus giving the 'HVDC premium' relative to the average level of socialisation onshore (if indeed there is one). This cost can then be divided by the distance, and MW rating of the circuit giving a MWkm figure which can be used in calculation of the expansion factor relative to a 400kV overhead line. Thus giving a proportional expansion factor, normalised to the degree of socialised assets in other parts of the network.

Further, we have a few comments on specific paragraphs in the consultation document:

- 5.24: £550m does not seem like an accurate estimate of HVDC converter costs. We believe it should be closer to £300m as the cable manufacturer Prysmian claim to have received ~800m Euros, against a total pot of ~1.1bn Euros for the Western link[1].

[1] http://investoren.prysmian.com/phoenix.zhtml?c=211070&p=irol-newsCorporateArticle_pf&ID=1661739&highlight=

- 5.26: HVDC converter stations are necessary to HVDC systems in the same way that HVAC substations are necessary to HVAC transmission. There is a difference in that the HVDC terminal equipment is generally higher as a proportion, than the HVAC equivalent – with AC circuit costs being higher.

- 5.61 – 5.63: Do the overhead costs include maintenance costs for substation assets? Or just the line elements? A very significant proportion of the maintenance costs on the network is tied up in substation equipment & auxiliaries, protection, control etc. We do however agree with keeping a constant expansion factor for simplicity.

- 5.77: Incorrect; a parallel cable ONLY could be used, not additional converter stations, to give double circuit type redundancy. This would need to be designed in from the outset though. There is some inherent security in the converter station, in that a single pole outage only results in a 50% loss of transmission capacity.

Our ref. 130115_CMP213

Islands

We have no specific comments on the Islands section.

Yours sincerely

Danielle Lane
Head of Regulatory & Stakeholder Relations UK
DONG Energy

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	Stuart Cotten (01757 612 751)
Company Name:	Drax Power Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We believe that the Workgroup has made good progress to date in identifying, and providing preliminary analysis on, options for each part of the Modification (i.e. sharing, HVDC and island connections). There is still a considerable amount of detail to be developed, particularly on sharing and the potential use of a diversity factor, prior to the commencement of the Cost Benefit Analysis. Please see our answers to the specific questions raised by the consultation (below).
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We believe it is too early to state whether the original proposal better facilitates the Applicable CUSC Objectives. We shall provide further comments on CMP213 when the Workgroup has had time to consider the views expressed in consultation responses and the proposer has had time to consider which (if any) options highlighted in the consultation (or in industry responses) they wish to adopt as part of the original proposal.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We believe implementation in April 2015 would allow parties time to react to forecast changes to tariffs (e.g. make decisions on TEC reduction or closure). In contrast, implementation in April 2014 would provide too little notice for users to react to tariff changes, given their obligation to provide notice to National Grid at least one year and five days prior to the Charging Year. Any implementation option that occurs midway through the TNUoS Charging Year is highly undesirable as this would not align with TEC reduction / closure decision timescales.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	Yes, the Workgroup has considered an adequate range of options. However, we believe that further consideration is required on the mechanics of a diversity factor and how this would be applied in the TNUoS tariff calculation. In addition, we believe further analysis is required on the merits of diversity at a local level. In particular, the correlation (or counter-correlation) of load factors of different plant types (some, of which, have not yet been subject to large scale deployment) that are geographically concentrated.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	Yes, we believe the Workgroup has identified a sufficient number of options for consideration. However, there is a lack of analysis on generator cash-flow implications for each option (e.g. where an ex-post reconciliation is considered). In addition, there needs to be a better understanding of how generators will treat the variable ALF methodology in their cost base. We continue to have concerns over the introduction of a long-run tariff that is directly affected by short-run dispatch decisions.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No, we have no additional views to those expressed by the Workgroup. We believe that all plant should be subject to the Peak Tariff, although the tariff applied to each plant should reflect the assumptions contained in the SQSS. This will ensure that the application of the Peak Tariff evolves as generation technologies develop.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Overall, yes. However, please see our responses to Questions 1 and 2.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	Our main views can be categorised as follows: 1. ALF: The methodology should use a Generic ALF approach that reflects the characteristics of different plant as captured in the SQSS for the same reasons set out in the Workgroup report. 2. Diversity: The methodology should contain a diversity factor to ensure that sharing is only reflected in a user's TNUoS charge where it is technically, and probabilistically, feasible. 3. Peak Tariff: We believe that all plant should be subject to the Peak Tariff, although the tariff applied to each plant should reflect the assumptions contained in the SQSS. This will ensure that the application of the Peak Tariff evolves as generation technologies develop.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	Yes, we believe each of the options could work.

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	Both the "most constrained boundary" and "multiple boundaries" approaches appear plausible. The original proposal, which places all converter costs into the wider locational element of the tariff, appears the best evidenced at present. We agree that it is sensible to pursue an option that removes some elements of the converter costs. However, more analysis is required to develop evidenced based justifications.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes, although please see the answer to Question 1 (above).
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes, the range of options identified appears reasonable. However, given the difference in technologies to be employed, geographical attributes and, thereby, associated costs of each island link, we currently believe the case for generic expansion factors is very weak. Additional analysis is required to develop a justification for generic expansion factors if such proposals are to be taken forward.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes, the range of options appears reasonable. However, we question the appropriateness of the SO “anticipating” changes to the generation background. We believe the charging methodology should attempt to reflect, as far as possible, the physical attributes and capabilities of the system.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes, the range of options appears reasonable. However, at present there appears to be little justification for applying any of the alternatives.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	To date, the original proposal appears to be best evidenced.

Q	Question	Response
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We believe implementation in April 2015 would allow parties time to react to forecast changes to tariffs (e.g. make decisions on TEC reduction or closure). In contrast, implementation in April 2014 would provide too little notice for users to react to tariff changes, given their obligation to provide notice to National Grid at least one year and five days prior to the Charging Year. Any implementation option that occurs midway through the TNUoS Charging Year is highly undesirable as this would not align with TEC reduction / closure decision timescales.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	We do not believe that a transitional approach is appropriate. The current process for notifying TEC reduction / plant closure, implemented by CMP192, should prevail. As such, the implementation timescales for CMP213 should work around this process. One year and five days has been signalled as the minimum notice period required by National Grid. Changing this process "at will" simply makes a mockery of the justifications set out under CMP192.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No.
Do you have any other comments?		No.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	Mark Cox
Company Name:	EDF Energy
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The matters concerned comprise the most complex code/market rule consultation we have yet seen since Vesting. It is clear that the workgroup still has much to do, including the definition of alternatives, of which there will be a number. There will certainly need to be a second consultation following this. It may be that that second consultation will comprise a slightly more compact and targeted document, which can help ensure engagement.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	CMP213 Original attempts to better facilitate the Applicable CUSC Objectives, but does so imperfectly. We do agree that now that SQSS has been amended under GRS-009, there is a need to update the charge calculation method to reflect that. There is also clearly a need to update the charge calculation method to reflect new HVDC technologies, and new Island connections. CMP213 Original attempts to address each of these. Overall we consider that the proposal is more cost-reflective, but it has flaws in the manner in which it treats intermittent generation and sharing more generally, and can be improved. We expand on this later on in this response. We believe that a variant of CMP213 is likely to be eventually chosen and implemented, once specific WACMs are defined, and that this WACM should be able to better facilitate especially (b), in that it better facilitates cost-reflectivity in the transmission charges, and, as a result of so doing, competition in generation, and (c), by ensuring that the use of system charging methodology properly takes account of the developments in transmission licensees' transmission businesses (regarding new topologies and technologies).

	For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are : *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	Yes. We would comment that if implementation should for any reason not prove feasible by 1st April 2014, then it should be on 1st April 2015, as a mid-year implementation would be very untidy in relation to TNUoS charges.

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	The workgroup has considered this matter. It seems clear that the concept of sharing by means of the application of a load factor to the year-round tariff element, does not reflect reality well where locally, one type of generation is dominant. Evidence is needed on the extent to which wind and wave power exhibit any counter-correlation. More detail is needed to better understand how each of the sharing and diversity alternatives work. We believe no sharing can safely be assumed amongst generation connected to local (pre-MITs) circuits. We therefore believe that local circuit TNUoS tariffs will not require adjustment as a result of whichever variant of 213 is eventually implemented. Generators are, anyway, perfectly free to request a TEC lower than their installed capacity based on, for instance, rarely generating at a wind farm's total site maximum output, if they believe this to be their reality.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	We believe that the proposal, in 213 Original, of the use of load factor alone as a dilutant of the year-round tariff element, is inaccurate – it does not reflect reality well. We would like to see the workgroup concentrate on working up methods 1, 2 and 3 of improving ICRP in the core of CMP213, further. These seem to be the areas where there is still the most work to do, and where there is strong scope for viable WACMs. We do agree with the comments in the consultation document on the concept of the application of load factor to the residual charge, which the Workgroup has decided not to take further; table 16 illustrates well the manifest drawbacks of this concept. We also agree that there are numerous potential flaws associated with both the Metered Output and FPN approaches to determining the ALF.

Q	Question	Response
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	The relevant question is to what extent in future, if there are large volumes of intermittent generation, NG might rely on some portion of it, even if small, to meet ACS peak demand. We note that the GSR-009 consultation stated, *"A scaling factor of 0% for intermittent generation is simplest to articulate and implement, but analysis of the wind data supports the inclusion of wind generation at 5% of Registered Capacity. This is because, against the dataset used, the GB 2020 wind fleet will be at 0-2% total output for an average of only 4 hours per year; whereas it will be at 2-7% output for an average of 160 hours per year".* We do consider this points to evidence in favour of intermittent generation, if it is to be treated as a single class, being exposed to the proposed Peak Security element of the TNUoS tariff at around a 5% level, and not the proposed 0% in CMP213 Original. We note that if there is significant tidal generation in future, and it continues to be included within the class "intermittent", then further review may be necessary.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We have set out our views on sharing in relation to local circuits in our response to question 1. We do believe that annual load factor alone is a poor indicator of the costs caused by incremental MWs in particular areas of the wider system, and that generation type (bid price) matters as well, as does the amount of other generation (with a different bid price) in the same area and the degree, if any, of counter-correlation – i.e. diversity is indeed key. Method 1 as referred to in the consultation is not yet well-defined, but is worth developing further as a priority. Methods 2 and 3 as referred to in the consultation both have merits, and we would like to see the workgroup's work programme as from now concentrate on further defining, and analysing the effects of, methods 1, 2, and 3 for handling diversity.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	We would like to see methods 1, 2, and 3 regarding how to take account of diversity of plant types, developed well as a priority for the workgroup – the workgroup's work on islands and HVDC issues is more well-developed, by comparison.

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes, the WG considerations in this area are well documented. The original CMP213 proposal appears optimal in this respect. The correct approach based on cost-reflectivity, is to take the annuitized unit capital cost (£/MWkm/year), including the converter cost as well as cable costs. The converter costs are clearly linked inherently to the technology, and so should not be excluded. The HVDC link is not being built in order to be able to route, or marshall, power. DC has been selected because onshore OHLs can no longer readily be consented. Therefore the route has to be sub-sea, and being elongated, AC is technically infeasible due to cable capacitance. The choice and cost of the HVDC link is inevitable, and the technology choice was not made for reasons of system control. The “controllability” of the HVDC link is largely irrelevant; its value lies in alleviating constraint costs that would otherwise arise, which would significantly exceed its capital cost. As to any comparisons with quad boosters, one of these would not have been built where the West Coast HVDC link is being built. If the converter cost were to be excluded, economic inefficiencies would result from the lack of cost-reflectivity in this regard. The converter cost represents real money which someone, somewhere has to pay for. The need for a new HVDC link is caused by generation North of it. HVDC converter stations must therefore form an integral element of the locational signal for these transmission circuit types, otherwise generators will be unable to internalise the transmission network cost impacts of new plant location (and existing plant closure) decisions. The cost of converter stations as a proportion of the whole will vary considerably for each HVDC circuit, depending on its length. In essence the converters represent a pair of fixed costs. Cost-reflectivity is best served by calculating a unique expansion factor on the transmission network for each of the very few HVDC circuits that come to exist.

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	It is important that the impedance chosen for each link is correct, and results in flows along the HVDC link that mirror those likely to obtain in reality. We have no additional options to propose.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	If an island is connected by HVDC, we agree with CMP213 Original as developed by the workgroup, so that the expansion factor for that technology is used based on annuitized cost. The need for such island links is patently driven by proposals for development of new generators on the islands, and not by demand growth. Regarding the selection of the impedance for HVDC island connections in the DCLF model : we support the application of the same approach as for the HVDC bootstraps (see reply to question 7).
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	See reply to question 7.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes. We believe that CMP213 original, which says to maintain the existing MITS definition, is the best approach to determining which island connections are classified as "wider" (and not to apply "sharing" to local circuits). We do have a concern that where an island does qualify as wider under the existing charging definition (of what is wider), there may be limited, if any, true generation diversity in terms of year-round output counter-correlation. It has not been established that wind and wave power counter-correlate, and there may be only limited existing, small-scale fossil plant (which may be closed medium term). The sharing factor for TNUoS charges to generators on islands that do qualify as wider need to reflect the degree of expected counter-correlation amongst generation technologies there.

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	As to any island connections which do qualify as "wider", we agree with the Workgroup that where there is no redundancy in their connection, their expansion factor should be scaled down by 1/1.8, so that the application of the global security factor of 1.8 in the charging model doesn't lead to an unfair outcome.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We support CMP213 original in this respect : the island expansion factor should be project-specific, based on the actual cost of the transmission project. We do appreciate that a result is that each project cannot know its *exact* TNUoS until close to the time of build. The advantage of this approach is that it is the only approach to this aspect that is fully cost reflective (thus meeting objective b). Offsetting the early uncertainty, the charges would be stable once set. As to whether new connections might be cheaper - the past is not a guide to the future, and most commodities are only becoming more expensive. Past reductions in the costs of some forms of connections, especially submarine cables, may not be indicative of ongoing, future reductions.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	If an island's connection is local, whether or not it might later qualify as wider if some more generation or demand came along (triggering grid expansion) is not something that NG should be attempting to forecast, or pre-judge. National energy policy is not sufficiently static for this to be reasonable. Moreover, NG would be subject to various pressures in making such an assessment. This possibility would be likely to politicise the electricity landscape, and to be damaging to certainty and stability. It may not lead to efficient outcomes. Anticipatory changes would have to apply system-wide, and would have to "anticipate" a MITs node becoming a local one, as well as vice versa. The problems are manifest. We would not support WACMs embedding this type of "anticipatory" assessment/allocation.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes, and we agree with the original on this matter. We do not have any other proposals or options that we would like to be considered.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	We agree with the proposed reduction in length of a connection to the mainland by 1.8 where it is a single link.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We think that implementation should be in April 2014 if a final decision is made by Ofgem by the end of September 2013, otherwise from April 2015. We do not agree with the concept (options 1 and 3) of a mid-year, i.e. non-April, implementation date – that would not fit with the charging year that users are used to, or with the way that TEC charging is and always has been structured.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Our view is that following the Ofgem decision, the usual CMP192 based penalties for early closure, or early cancellation of a pre-commissioning generation project with a signed connection agreement, should still apply. The risk otherwise is that generation projects which for reasons other than CMP213 are considering terminating or closing, would be able to misuse the transitional arrangement. This would undermine the new user commitment that has only just been introduced after extensive national debate. There would be a risk in consequence of, in a number of cases, exposing consumers to additional costs from stranded transmission assets, especially as regards speculative new projects.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No, but we would particularly like to see methods 1, 2, and 3 as to how to accurately take account of plant diversity in the improved ICRP model, fully worked up into WACMs by the Workgroup as a priority, as this is where there is the most work still to do, and it is fundamental. Our views on other possible WACM components are contained in the answers to the questions in this consultation.

Q	Question	Response
Do you have any other comments?		No

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	Michelle Dixon
Company Name:	Eggborough Power Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	It is difficult to comment on these complex issues without having been party to the discussions, but we hope that the following comments are helpful. Generally Eggborough Power Limited (EPL) are concerned that the tone of the work seems to be looking at ways to lower the transmission charges to renewable (or intermittent) plant in a move away from cost reflectivity. Ofgem's general approach to monopoly charges has focussed more on the capacity element than any commodity usage, arguing that the TO builds its network for meeting a peak system usage and those connected must pay, irrelevant of their technology. As we move forward, with wind expected to achieve higher load factors and coal/gas becoming more variable, there is a risk that the methodologies proposed will have simply placed more cost onto the existing plant with no economic rational. Using historical load factors seems to move charging towards a backward looking, potentially discriminatory regime. The principle of equitable, cost reflective charges should be maintained. We understand the principle of not charging companies for assets that are not there, and agree if the TO does not provide the peak capacity on the wider networks the parties should not be asked to pay for it. However, this could be done by having "firm" and "interruptible" access rights, rather than giving a blanket discount. That would possibly allow other parties to opt for similar rights. Sharing is a well established principle in gas, where the "interruptible" products have been used for years. We support

	generators being able to pay lower charges for interruptible rights, but the interruption is a business risk that a customer may or may not choose to take on. The idea of using load factors is highly risky and has the potential to be very wrong; look at the changes in gas and coal stations over the last year. EPL does not believe that intermittent generators should not be exposed to paying for assets if they do utilise them. The calculated sharing factor seems to put the TO in charge of saying who is sharing capacity, rather than possibly looking at the potential to share (wider capacity) and then offering reduced tariffs (say via a tender) to the parties who wish to have less firm access rights. On the HVDC links, EPL believes that the converter costs form part of those links in the same way that the local substation used by a power station forms part of its charges if it is the sole user of the assets. However, we believe that work done on load flows will need to try and establish a "reasonable" approximation to the modelling on the AC network. EPL has no comments around the island connection work.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.* On balance, given the current status of the proposals, EPL does not believe that the original modification better fulfils the relevant objectives as it does not appear to be cost reflective when compared to the base line (objective b).
Do you support the proposed implementation approach? If not, please state why and provide an alternative	

suggestion where possible.	

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	It looks as if the workgroup still has some way to go on their discussions. Generally EPL feels that the methodology should be technology neutral to maintain its cost reflectivity.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	Without being at the meetings, we suspect the workgroup has given due consideration to the issues.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	As noted above, EPL has some concerns about generators who can access the system at peak times not paying for the investment that allows the TO to accommodate peak flows. While there is some implicit sharing occurring, we are not convinced as the system develops that what is really needed is some form of “less” firm access rights, with associated lower charges. At times in the past there was a push by Ofgem to move the market to access rights that could be explicitly traded. We were never of the view this could work, but we think a more pragmatic approach could be to consider non-firm rights. Under such a regime the generator would get discounted charges in return for the TO being able to call him off at times of high system usage or constraints. At the current time the TO can manage the system using the BM, bidding plant off, but not having to face the financial consequences itself.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	EPL has no specific item to add to the workgroups considerations.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	There has to be good reasons to treat different types of generators differently. When a wind farm or a coal fired plant is generating the power flowing over the wires is MWs and it therefore appears to be unduly discriminatory to treat one differently to the other. As noted above we feel very uncomfortable with the idea of using historic load factors or operations to dictate prices going forward. This could create significant price volatility (for example wind all had a high load factor last year so has a low charge this year, but it turn out to hardly run). The RIIO framework already appears to make it more likely that monopoly charges could suffer from increasing volatility and the regime should do nothing that would make that situation worse. EPL is also unclear what the incentives would be on plant. AT the current time the TNUoS charges incentivise connection in the south. Would getting low prices at a certain point of load factor cause odd operating regimes? My load factor will be too high if I run in March, and given how high the prices are I best stay off the system?
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes. This appears to be a tricky issue. EPL does feel if reduced charges are required to offer a further subsidy to the windfarms connecting into these wires then it would be best if we were explicit about that subsidy.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	It looks from the report as if the group are still considering these issues.

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The group appear to be trying to create a model that will allow the new links to fit into the existing methodology, which seems reasonable.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes, though we recognise that the way the connections were configured historically may create some anomalies. However, the same is true for conventional generators who also get different charges arising from historical engineering decisions.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	EPL will wait to see the additional work of the group before making further comments. However, we agree that where the network expands using HVDC links those links should all be treated in the same manner.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	EPL would favour a 1 April implementation, but are indifferent if it is 2014 or 2015 on the condition that the parties have sufficient time to consider and plan around the indicative charges.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Whether a transition is needed depends on the solution.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No.
Do you have any other comments?		No.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	*Neil Kermode – Managing Director - Neil.Kermode@emec.org.uk*
Company Name:	***EMEC***
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The consultation is useful as tool to comment on the development of the project TransmiT issues in the CMP process but does not give enough detail for respondents to realistically assess impacts of the Original. This statement is even stronger for the likely alternatives. It would be unfortunate if stakeholders did not have a chance to influence any material change to the direction of the process once sufficient detail becomes available.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* As far as the Scottish Islands are concerned there is no set methodology with which to compare the Original. It is probably fair to say that the Original may yet be changed after this consultation and before its submission to the CUSC panel. However if the Original does not allow for local sharing by load factor (or otherwise) and, in turn, leads to high and/or volatile locational charging and consequently an increasing and disproportionate gap between Islands and the rest of the GB system then there would be a significant issue as far as competition is concerned. *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their*

	transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); The Original, in its present form, may not offer a consistent signal for cost reflectivity when looking at the way expansion factors are calculated for traditional network assets and newer technologies. *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	It would be desirable if implementation was 1st April 2014 but in order to resolve key issues it may mean that some of the parts of the later process need to be shortened – or a period of transition allowed – to allow for further work in the Workgroup.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	The important phrases in the question appear to be*' .areas dominated by one type of generation'* and *'including local circuits'*. For Diversity, the analysis seems incomplete as there is a basic assumption that intermittent generation cannot share and - on a year round basis- thus remains perfectly correlated. All are deemed 'must run' and that all will be running together and with similar Load Factors. Local Sharing – would introduce a sharing factor for Local circuits, including Scottish Islands, which would depend on modelled outputs assessing scenarios with only intermittent renewable generation (and some local demand). As 'Other options' it may be worth suggesting that wind generating plants sited over a wide geographical area could also be modelled for anti-correlation of output –rather than assumed as 100% correlated (all running at the same time) in 'Diversity' and, so far, in the Island model

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	The WG has sufficiently reviewed the options for the calculation of ALF.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No additional suggestions
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Forward looking application of sharing is an integral part of Local sharing otherwise sharing – in charging terms – could only be applied AFTER other generators of different types joined the circuit. In the rest of the (Wider) network sharing is generally anticipated. This could be further developed in the WG. It is noted that the issue of local/wider definition and how that should be dealt with as far as application of ALF is concerned for Islands is ambiguous in the report. This may mean that responses to this consultation may lack a degree of clarity –reflecting confusion regarding the consequences of the stance of the Original and Islands meeting the definition of Wider. (See 6.101 p 130 and table 19 p 122-123 of the WG report). Work needs to be done in the WG to clarify this issue.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	It may be that: Sharing, if it is truly reflective of use and of generator type, should apply throughout the system including in parts deemed local – but serving several generators. Or That cost reflectivity is best served by using a simple, but generator specific, load factor – as in ALF, whilst adequately representing networks which, whilst they may be on the periphery, are integral parts of the GB onshore transmission system.

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	See our response to Q12. We do not consider that the argument that HVDC links, which parallel and are fully integrated with the GB onshore network, should be treated the same as OFTO arrangements to have validity. Consideration of factors to be included in the expansion factors of AC and HVDC onshore solutions should be treated in a consistent manner. It appears that an overly simplistic view was taken on HVDC converter stations – i.e. as they are more expensive than AC substations their costs should be fully locational. However taking an overall view of HVDC compared to traditional AC, not only is the technology superior, costs are in line if not lower than AC and environmental impact is much less. Where HVDC offers the optimum solution its implementation should not be impeded by charging methodology.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	The basic premise that that HVDC load flows are linked to AC network boundaries is covered. There could be further consideration of the benefit in network management offered by HVDC technology and how this might be reflected in locational and non-locational TNUoS.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Referring to 5.73 – 5.78 p114 The cost of single v double HVDC links has not been ‘bottomed-out’ with hard data – it may be worth looking further at this.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	Should the SO or TO’s be allowed to build an HVDC link which would be more expensive (in terms of Locational TNUoS for triggering generators) but cheaper in real cost terms than a conventional AC link (plus its fixed infrastructure) ? It would appear wrong for this to happen, especially considering the technical and environmental benefits of HVDC. Should specific HVDC cable expansion factors be used considering DC cables are cheaper than equivalent AC, yet generic AC cable/overhead factors lead to lower TNUoS?

Q	Question	Response
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Though the Original includes Islands classed as Wider in the potential reduction in Locational TNUoS (compared to the Status Quo) afforded by ALF – there have been indications from WG discussions that if all (or even some) of the Scottish Islands triggered ALF that 'Diversity' (as described in the table for Q1) would be introduced into CMP213 in order to 'correct' the' anomaly'. It is worth looking closely at table 19 produced on P122-123 for the range of issues in Islands but in particular at '5. Sharing' and 'Action Required'. It is interesting to note that for 'iii Maintain Existing Definition' (apply Wider when and if an Island 'qualifies' the same Action Required as All Classed Wider. See also response to Q4 The view expressed in 6.101 (led by National Grid) that tariffs should be similar whether Islands are classed as local or wider needs further development.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	There may be some problems in how the potential alternatives may be worded. Though option vii is described as no potential alternatives being considered, this was not the case for option viii which is described as having support. It may depend on how redundancy is measured if 2 single (not double circuits) comprise a Wider link to an Island. If each circuit was only half or less of the total TEC connected then would there be redundancy?
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Arrangements already in place for Offshore (OFTOS) are often used by some WG members to argue that Island (Radial) links should be treated the same. That translates to inclusion of Converter Station costs within the Expansion Factor and hence locational TNUoS. We believe that this thinking is flawed and does not take into account significant, and critical, differences between Island's relationship to the onshore GB network and connections to offshore wind. We do not feel that the arguments for including all Converter Station costs for HVDC but excluding substations and Quadrature Boosters in AC been adequately justified. We believe that there needs to be more consideration, including further analysis, of links which compare AC versions of all or parts of links with HVDC alternatives insofar as capital cost versus eventual TNUoS are concerned (5.46-5.54 pp110-111). This is also pertinent to Q6 above.

Q	Question	Response
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Whilst the MITS definition is linked to the level of sharing allowed for in the charging methodology this may need to be considered in a more forward looking manner.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Could the Island sharing modelled in the ICIT work be expanded to look at sharing generally between Intermittent generators and also look at how a single renewable generator type made up of plants spread over a wide geographical area may have a degree of inbuilt counter-correlation?
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	• If Island sharing is to be used as a factor within the methodology it would need to be codified, that is transparent and predictable for those who need to know what their TNUoS is likely to be. There would be a concern if sharing could only be applied after the fact (only after other types of generation actually joined) or if sharing/not sharing was effectively determined by the TO on a case by case basis – which may lack the necessary transparency needed by generators , not least for investment purposes. • Where Islands conform to the definition of Wider there should be no reason why they should not be treated as any other part of the onshore network. • Island links, where they are radial HVDC, should be treated in the same way as parallel 'bootstrap' links as far Expansion Factors are calculated. • For all links the methodology would need to avoid the prospect of uncertain and volatile charges for generators in certain areas – one of the major underlying reasons for such are likely to be unstable and rising single project costs which are then input as the Expansion Factor. It is difficult to compete effectively if others can make use of smoothed out (averaged) costs which are far less prone to sudden and unexpected increases in the locational TNUoS. • A Security Factor of 1.0 (whether Wider or Local) should be used for links where there is no redundancy.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	1st April 2014 with transition option Otherwise if no transition option then 1st April 2015 would be more feasible.

Q	Question	Response
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	See Q 16. Yes if implementation on 1st April 2014 – then shorter notice period allowed.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No
Do you have any other comments?		No

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	*Paul Jones paul.jones@eon-uk.com*
Company Name:	*E.ON*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Please see below in our response to the individual questions asked in the consultation.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.*

	No, mainly on the grounds that we believe that it is not appropriate to charge on the basis of load factor, especially a historic one. We do not believe that load factor is the sole determinant of the amount of constraint costs connection of a certain plant could cause. Also historic load factors do not represent future load factors.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	As no specific implementation approach was specified, please see the answer to Q16 below.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	The range of options has been identified but not fully explored in all cases. There appears to be more work to do on the options that take into account the amount of diversity in an area along with the load factor of plant. Presumably this will be taken forward by the working group as a next step.

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	It has reviewed all of the options. However, we believe that a backwards looking ALF is problematic as an indication of a Load Factor going forwards. If investment is made on the basis of a view of how LFs will affect constraint costs then it must be forward looking. One aspect that the workgroup doesn't seem to have considered fully is what the load factor signal is seeking to achieve in terms of generator behaviour. If a station is to be charged on the basis of its load factor then we would expect it to be able to react to this signal in some manner. In the current methodology the signal is seeking to influence generator build and closure decisions. A generator can react to the current price signal by choosing to build a new power station or close an existing one at a particular location. If load factor is introduced as a charging parameter, then the aim must be to influence behaviour accordingly with respect to that load factor. If a generator is unable to react because it is based on historic performance, then it is not clear why the signal is being sent and what it is aiming to achieve in terms of efficient behaviour on behalf of generators.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	Intermittent generation should be exposed to the peak security element to the extent that it drives investment made to support peak usage. In the work undertaken to support SQSS change GSR009, a 5% availability factor was assumed for wind, but was scaled to 0% as there was little practical difference. It may be appropriate to applying 5% for the peak charge or to keep the treatment as proposed and to review the situation if the contribution to peak increases in future.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	As we state above for question 1, the sharing options haven't been fully explored and more work needs to be done on how to potentially reflect diversity going forward. Also, further work could be done on whether a forward looking Load Factor would be more appropriate.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	Assuming that the LR/SR cost equivalence assumption is robust, the methodology should seek to reflect different characteristics using more than a load factor relationship as diversity of plant in parts of the network and associated bid prices clearly have a significant influence too. Rather than trying to apply individual characteristics through ALF, it may be better to reflect effects more generically. After all, investment in the network will not be made on the basis that individual stations are predicted to be generating at precisely the same output that they have achieved in the previous 5 years, so why should the charging seek to do so? We see merit in exploring a forward looking load factor solution with a simple cash-out mechanism for overrunning, if load factor is included as a parameter in the proposal.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	Yes.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.

Q	Question	Response
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	We believe that there is a case for removing some of the converter station costs from the calculation of the expansion factor, but only where it is clearly demonstrable that they would have been incurred for an AC equivalent and charged through the residual too. This should be assessed on a case by case basis for each HVDC circuit as circumstances of each link are likely to be very different. It would certainly not be appropriate to treat these as 400kV overhead lines. The model should seek to ensure that the HVDC's impedance is represented so that a "fair share" of flows occurs on HVDC assets when it is run. The approach set out in the original at present seems to do this most appropriately.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.

Q	Question	Response
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	There should wherever possible be a consistent approach with HVDC elsewhere. We are less concerned about how assets are classified, as long as a consistent approach is adopted across the charging methodology. For instance we believe that where it can be demonstrated that local assets are shared that this should be appropriately reflected in charges. However, we do not support an anticipatory approach to sharing.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We would not support a mid-year implementation approach. We continue to believe that major charging changes should occur with effect from the beginning of a charging year. If there is time to implement by April 2014 then this would be acceptable as long as sufficient notice of new tariffs is given to participants (see answer to 17 below). Otherwise, implementation should occur in the following April.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Sufficient notice of probable charging effects should be given to allow stations to make TEC reductions where appropriate in good time without fear of a penalty charge being applied under the CMP192 arrangements.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No thank you.
Do you have any other comments?		No thank you.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	Mike Davies 020 7484 8573 Mike.davies@futurelectric.co.uk
Company Name:	Future Electric Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We appreciate the considerable work done to date on this modification proposal. Our one principal concern is that this has not yet looked at the financial implications of the changes under consideration. This modification is complex and there is a risk of unforeseen consequences. It will be too late in the process when an Economic Impact Assessment is available to address apparent defects. Despite the potential delays, we urge the workgroup to reconsult with the benefit of some meaningful economic forecasts.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	Without some economic analysis we are unable to tell if the original would definitely better facilitate the Applicable CUSC Objectives in a number of respects. In specific relation to the proposed treatment of HVDC lines however, we firmly believe it does not better facilitate the Applicable CUSC Objectives. More details appear below.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	Early implementation is far preferable to delayed implementation although we would not wish to see this happen at the expense of full consideration. Where we see the potential for flex is in the required notice period from a decision up to the point of implementation. We consider April 2014 to be a realistic target.

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	We view the distinction between types of generation as important. For example low carbon generation can be from quite different technology types where more diversity may exist. There is a risk of over-building as a result of taking too simple an approach to this.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	Yes we do.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	We question if the use of the two part locational model is needed but it would be very helpful if economic outputs could be provided. These would enable us to see the effects of different treatments on different generation types in differing locations around the UK.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Where quite different technologies such as wind and wave/tidal can both exist on a system, there may be merit in more work on a suitable sharing model.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	As mentioned above, more work may be useful on the interaction of different types of low carbon generation.

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We consider that a fundamental issue is being overlooked in the pursuit of a theoretical goal. For a TO, their licence obligation requires them to choose the most economic and efficient connection. In a case where the costs of AC and HVDC alternatives are close, a generator triggering such works should be indifferent to the choice made by a TO, especially since he cannot influence it. Therefore the choice of technology by a TO should not impact the generator in any way. Here the proposals do not take this simple fact into account. In the absence of an economic analysis it is unclear exactly what effect the different alternatives might have but it is reasonably clear that they would have some distorting effect. We feel this is clearly wrong.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	We reiterate our point above. It is not right that technology choices made by a TO should impact generators unable to influence those choices.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	See above.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The approach adopted must not be allowed to distort generator charges when compared to the use of AC alternatives.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	As far as we can tell in this complex paper, it has. This is subject to our comments about sharing in the context of different renewables technologies as mentioned above.

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes we consider that the Workgroup has considered all relevant options and potential alternatives.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes we do, subject to our comments about the approach to HVDC above.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	This is one of the areas in particular where it is difficult to assess the impacts of different approaches on TNUoS charges without some economic analysis. That would go to the heart of the CUSC objective about facilitating competition.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes we do, subject only to our specific comments above on HVDC, sharing and some economic evaluation to support alternatives.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	Local/Island sharing- which should be consistent whether they are local or wider HVDC Expansion factors consistent with AC onshore technology.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We favour Option 2 which is near term but we consider allows time for more work to be done.

Q	Question	Response
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	No we do not consider a transitional approach is needed.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No we do not propose to raise a Workgroup Consultation Alternative Request. Should the Workgroup take on board our comments above then members may wish to raise an alternative themselves.
Do you have any other comments?		Once again we wish to thank the members of the Workgroup for all their time and effort in developing this complex modification.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	**Simon Lord** Head of Transmission Services GDF SUEZ Energy UK-Europe Tel. +44 (0) 1244 504601 Mob. +44 (0) 7980 793692 simon.lord@gdfsuez.com
Company Name:	GDF SUEZ Energy UK-Europe
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*Original No* *Method 1 No (further definition required)* *Method 2 Better* *Method 3 Best* *The original has two key ingredients:-* ***Load factor.*** *The load factor is used to reduce the location element of the transmission charge. This is not cost reflective in that in areas with low or no diversity of plant type a reduced location charge*

	is applied to low load factor plant when in practice significant transmission reinforcement can be required. In some circumstances an element of poor cost reflectivity could be accommodated based on the simplicity argument. In this situation though it goes to the heart of the modification and would favour low load factor plant in a zone when in practice high load factor plant with a different characteristic and/or fuel type would lead to no or limited transmission investment. ***Dual background*** *The load flows that are used to calculate the peak and year element are based on two separate backgrounds. One is based on peak flows excluding intermittent plant and the other is based on SQSS set parameters that are an approximation for a full cost benefit calculation.* *We believe that there are two issues with this approach.* • *Intermittent generation is not charged the location element of the peak security load flow. We believe that there is a compelling argument that intermittent generations should contribute to the peak security element. Absent changes to demand (given a compliant system as at present) only reductions in conventional plant lead to investment for peak security, one main driver for this is additional intermittent generation. Additional intermittent generation with low variable cost reduces the energy need from conventional generation and over time the volume of this type of generation available. Reduced conventional generation increases the need for reinforcements for peak security. Given this strong relationship we believe that only a single back ground should be in all scenarios or intermittent should be charged for the peak scenario.* • *An incremental methodology is based on a single back ground. The duel background is not mathematically rigorous as data from each independent back ground is added together which, whilst creating a charge, is not an appropriate use individual back grounds.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	*N/A*

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	*Yes the group has considered the geographical issues and arrived at a methodology to incorporate sharing based on a number of solutions. Whilst the cost is based on an incremental methodology the sharing need not be based an incremental methodology. The relationship in Method 1 includes a type of incremental sharing where full benefit is given to plant based on the ratio of carbon/low carbon plant in a zone. Indications are this may be a "flip flop" type approach with all zonal km either shared or not shared but further work is required to define the exact relationship. Methods 2 and 3 include an appropriate sharing based on analysis with method 3 on a zonal basis producing the best solution.*
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	*Whilst the group has considered the various options for the calculation of ALF we do not believe that any of the proposals reflect the ALF used in planning timescales and all methods will result in arbitrary charges based on historic plant operation. ALF needs to be used in combination with bid-offer differentials in Northern zones and offer-offer differentials in southern zones for it to reflect the relationship to constraint costs and hence transmission builds.* *Analysis has clearly shown the relationship between constraint costs and bid price, this is not captured by any solution based purely on ALF.*
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	*Intermittent generation is not charged the location element of the peak security load flow. We believe that there is a compelling argument that intermittent generations should contribute to the peak security element. Absent changes to demand (given a compliant system at present) only reductions in conventional plant lead to investment for peak security, one of the main driver for this is additional intermittent generation. Additional intermittent generation with low variable cost reduces the energy need from conventional generation and, over time, the volume of this type of generation available. Reduced conventional generation increases the need for reinforcements for peak security. Given this strong relationship we believe that only a single back ground should be in all scenarios*

Q	Question	Response
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*Yes although a subsequent modification could consider sharing within the two broad plant categories. E.g. low carbon category could consider tidal and wave interactions at a local level.*
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	*We believe that reduced transmission investment is driven by the combination of generation type in a zone. It is the generation type (fuel source, load factor, bid and offer prcies etc) that drive reduced transmission. Thus an appropriate methodology could charge all generation in a zone based on their impact on sharing where this is done it should include both load factor and bid price. One cannot be used one without the other.* *A simplification of this is to charge all generation in a zone based on the combination of plant type in that zone. This will deliver the right message where parties considering location need to take account of the characteristics of plant in the zone and zones where power will subsequently flow. Method 3 where the benefit of reduced transmission investmentis shared on a zonal basis produces the best result.*
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	*Yes*
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	*Yes*

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*Yes*
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	*As per the original*
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	*We believe that sharing should be allowed on local circuits where it is included in the design of the connection and can be objectively justified. Simply classifying Island as 'wider' to benefit from wider sharing is not cost reflective and will result in inappropriate charges if sharing is based on the original proposal.* *We believe that the litmus test for sharing is that it should work for island. Method 3 works for islands and would result in shared benefits for all island generation where there is diversity of fuel source. Diversity with future generation types (e.g. tidal/wind) will need to be subject to a further incremental CUSC modification as to attempt to include it at this stage where there is limited deployment of tidal would add complexity at a time where there is already a multitude of issues being dealt with.*
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	*Yes*

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	*Yes*
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	*Yes*
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*Yes*
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	*A percentage of the HVDC converter cost should be excluded from the specific cost, based on its equivalence with onshore substations.*
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	*Method 3 has significant merit in that it is cost reflective at a zonal level and will result in transmission charges being better aligned with transmission reinforcement cost. The original and method 1 are relatively poor as they do not reflex diversity to any meaningful extent in a zone.*
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	*We believe that charges should be implemented as per the current methodology. There should bethree months notice of indicative charges with charges only changing on the 1st April.*

Q	Question	Response
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	*No*
Do you have any other comments?		*No*

HIE
Highlands and Islands Enterprise
Iomairt na Gàidhealtachd 'snan Eilean

cusc.team@nationalgrid.com 15/01/2013

Dear CUSC Team

Highlands and Islands Partnership Response to CMP213 Working Group Consultation January 2013

Highlands and Islands Enterprise (HIE) is the Scottish Government's agency responsible for economic and community development across the North and West of Scotland and the islands.

HIE along with its local partners: the democratically elected local authorities covering the North of Scotland and the islands: Shetland Islands Council, Orkney Islands Council, Comhairle nan Eilean Siar, Highland Council and Argyll & Bute Council make representations to key participants on behalf of industry to influence the way in which grid construction is triggered, underwritten then accessed and charged for in the region.

HIE and its partners have been closely but not directly involved with the working group process and the response below aims to provide additional input and comments not already expressed by Working Group members. In developing this additional input we have worked very closely with Scottish Renewables.

Process and timescales

Our view is that whilst the consultation itself is very detailed, there is not yet enough information to understand the implications and "bottom line" of the main Alternatives.

We would like the Working Group to consider release of preliminary impact assessment results, or at least modelled tariffs, prior to submitting the Working Group report to the CUSC Panel. This could be facilitated through TCMF or via some other informal route where the information is released to industry. This would facilitate gathering wider views into the Working Group which itself would in any event be refining and finalising proposals in view of modelling work.

It seems almost certain that there will be a Diversity Alternative or Alternatives, but there is still a body of work to complete before it is possible to address questions such as: the direction of travel for tariffs; volatility implications when plant enter and leave a zone and other outcomes.

We are conscious that these comments also hold for island sharing proposals brought forward by EMEC, Scottish Renewables and ourselves, in so far as the proposals are not fully developed. We therefore understand the pressures the group are under and the balance between consulting before or after something is fully developed.

We would welcome further industry comment as and when these proposals take more concrete shape.

Further specific comments on each part of the proposals are as follows:

Diversity
The proposals on Diversity seek to localise cost reflectivity in zones, giving a sharper cost signal. We accept that it can be demonstrated that relationships between load factor and constraint costs aren't uniform across the network, but we do not accept that the proposed solutions address this. They seek to take account of bid prices but do so in a way that themselves require some, frankly brave, assumptions and have not yet been tested. Therefore we are not convinced that there is an improvement in accuracy, whilst there is definitely an increase in complexity which will also impact on predictability and increase volatility.

Island expansion factors
As you will know, many industry participants remain concerned about the level of potential charges for the Scottish islands, and the targeting of cost risks onto developers (e.g. the assumption that generators need to absorb cost increases after they have placed user commitment and proceeded to build their project, as evidenced by recent events in the Western Isles).

Island developers also feel at a disadvantage to mainland developers where some cost categories are more readily fed into the residual component, but where there is a reluctance to mirror this for radial and island connections. E.g. recent cost increases for the Western Isles link have been attributed in part to discovery of more difficult ground conditions, which it is assumed will be passed through in locational charges. The costs of tunnelling on the mainland are not, however, passed through locationally, presumably in part because these costs are high and specific to ground conditions and so difficult to predict and genericise.

It's difficult to argue that generators shouldn't see a cost signal associated with the choices they make, but the islands at the moment appear captive to choices made by others at a late stage in development making investment very difficult.

Whilst the level of charge is perhaps not something that the CUSC can address directly, relative cost reflectivity, predictability, stability and promotion of competition do sit with the CUSC. HIE and its partners therefore support the Scottish Renewables proposal of generic island expansion factors being considered in more detail by the Working Group; perhaps even that remain fixed or index-linked for a particular asset rather than a price control period.

Sharing and Local / wider definitions
HIE and its partners, along with Scottish Renewables, have participated in the development of a local sharing option for islands and are therefore naturally supportive of it. We will read others feedback on the proposals with interest.

The local / wider debate around islands is largely one that is attached to sharing and how it applies to the islands. One concern is that islands might be dominated by one technology and that there is little sharing. Diversity attempts to address but still has generic assumptions that do not fit the island context or indeed other circumstances that have a mix of low carbon generation with some sharing.

Another related concern is that generic assumptions on transmission investment are less likely to be applicable where there is just one single circuit connection to the mainland, and that in this instance a more specific approach is desirable. If the Working Group were to address this through a change in local / wider definitions, we strongly favour developing a new definition for local / wider in the CUSC as applied to sharing, rather than risk consequential impacts of changing existing definitions. Even with a limited change in the definition, we would welcome further consultation to understand what is proposed and to have a chance to comment.

HVDC

The consultation has a comprehensive set of options for the treatment of HVDC and we don't have any major comments to add.

Process going forward

HIE and its partners along with Scottish Renewables believe that sharing, islands and HVDC should be constructed as if they were separate Modifications so the content of one can't influence the attractiveness of another. The number of possible permutations for one mega Modification inevitably risks either prematurely ruling out options or creating a complex and unwieldy process. We would ask the Code Administrator to consider whether it is possible, without causing further delay, to separate each area and provide equal weighting to developing Modifications for the purposes of submitting to Ofgem for consideration.

Yours sincerely,

Calum Davidson
Director – Energy & Low Carbon
Highlands and Islands Enterprise

In partnership with:
Shetland Islands Council
Orkney Islands Council
Comhairle nan Eilean Siar
Highland Council
Argyll & Bute Council

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	***Alist*air Buchan** **Chief Executive** **Orkney Islands Council** **School Place, Kirkwall, Orkney Islands, KW151NY**
Company Name:	**Orkney Islands Council**
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The Consultation document deals at length with complex issues and provides a reasonable insight into the deliberations of the Working Group without giving a clear indication of the majority thinking on some key issues. Matters covered in it are of interest not just to existing and potential generators but also to a range of stakeholders with interests that will be affected by the outcome of CMP213 – and Orkney Islands Council is one example of such a stakeholder, with an interest in building a local renewables industry, the success of which is highly dependent on the outcome of CMP213. The process should be more accessible to stakeholders with wider interests than the direct financial interest of generators.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	In respect of island charging methodology, there was no clear baseline with which to compare the Original. The Council is concerned that the proposals in the original for a cost-reflective island charging methodology are simplistic, resulting in excessive transmission charges which will deter renewables development in the area of the richest resource in the UK, thus inhibiting competition. No account is taken of the potential for network sharing in the islands, based on different renewables technologies and different locations and local conditions at individual project sites around the islands. It would appear that whilst there are certain arbitrary exclusions from the cost-reflective calculations on the mainland, for example

	the exclusion of tunnelling costs, a different approach is taken in the islands where every effort is made to include everything into the cost reflective calculation. *For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	No Comment

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	No. The Consultation document itself states that full consideration has not yet been given to the Heriot Watt research into network sharing between different renewables technologies in Orkney, and by extension in other islands. The Council welcomes the statement in the document that it is planned to further consider this research. The phrasing of this question, 'dominated by one type of generation', appears implicitly to put all renewables into one category, 'intermittent generation'. The characteristics of the various renewables technologies need to be explicitly recognised, and the Heriot Watt research is a sound starting point for this. It still needs to be further developed, in particular in respect of the simplifying assumption of a single point location for all wind generation, which ignores local conditions which could contribute to counter-correlation.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated Are there any areas that you think may need further development? If so, please specify along with an associated justification.	Yes, the Council considers that all options have been included.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No, not applicable to islands whilst they are local.

Q	Question	Response
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	As is the stated intention in the document, further consideration needs to be given to the evidence presented in the Heriot Watt research on network sharing between different renewables technologies. This should be the basis for a sharing factor which, in the interests of simplicity, should give a sharing factor which can be applied across the board to islands, as with ALF on the mainland. This would also serve the important purpose of giving greater certainty to developers making financial projections for possible projects. This also requires that the island sharing factor is applied on an anticipatory basis, as is effectively the case with the ALF proposal on the mainland. Without an anticipatory basis, there will be a perverse incentive for a developer to hold back in the hope that others will shoulder the initial charging burden.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	The Council believes that it is right to develop a methodology which tends more to reflect usage of the network by different technologies, rather than purely installed capacity.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	The Workgroup has considered a number of fairly technical options, the Council is not qualified to comment on whether this range of options is exhaustive.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	As 6) above

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	As 6) above
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The Council believes that given the widespread benefits to a range of generators, to the System Operator in terms of greater control, and also to Demand at a national level, the cost of HVDC circuits that parallel the AC network should not be locationally charged, but should be socialised. The technical discussions about which elements of converters, if any, to exclude from the cost calculation, are arcane. There is merit in simplicity in charging and there is adequate justification, as indicated above, to socialise the costs.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	As indicated in earlier answers, further consideration and development of the Heriot Watt model is needed.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes, there is straight forward and fairly unarguable logic in applying a security factor of 1.0 for single circuit connections with no redundancy. It is difficult to see any other options worth considering.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	No. The Council believes that, in compliance with EU directive 2009/28/EC, which requires 'reasonable connection costs' for island regions and regions of low population density, in order to ensure they are not 'unfairly disadvantaged', consideration should be given to the option of setting a limit on island expansion factors, whether for AC or DC, relating them to overhead line costs on the mainland. The disparity between projected island charges and those on the adjacent mainland are excessive – on the basis of Redpoint modelling a factor in excess of 6 times the mainland charge. The islands are an integral part of UK territory, with demand as well as enormous potential for supplying renewables to the UK, they should not be treated as offshore generators. The consultation document itself draws attention to the differences, in para 6.93, and the Council strongly supports those comments. The discussion document also rightly draws attention, in respect of island expansion factors, to the need for developers to know in advance of completion what the transmission charges in the islands will be. The absence of this knowledge increases uncertainty for developers to such an extent that it is difficult to see how they can properly plan for projects in the islands, and consequently such plans may not progress. The evidence of delay in island projects is already there, and has now contributed to the deferment of cable completion in Orkney by two years, to 2018. In the Council's view the islands expansion factor should embody a fixed relationship between charges in the islands and those in the nearest mainland zone.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes. The Council believes that the islands must in time become part of the MITS, on the basis of current definitions and because in the future, the islands will be at the centre of an onshore and offshore network of renewables generation, and thus an integral part of the MITS.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	The Workgroup has considered many options for the islands but the overall impression of the Consultation Document is that it has on the whole considered islands as appendages which need to be squeezed into the logic of a transmission charging technology designed for a different era of large centrally-located fossil fuel generators. Despite the growing importance of sustainability, and the direction of travel of Government policy, there appears to be little vision and no recognition of the fact that the UK will increasingly depend on power which can best be generated at the periphery of the UK, rather than at its centre, and that transmission charging methodology should work with the grain of this development, in order to facilitate it. Locational transmission charges send signals to generators which run counter to the necessary growth of renewables at the periphery of the UK, and thus amount to a burden on that development. The islands will in future be a key part of meeting the UK’s energy needs, collecting power from a range of different technologies located on the islands and in the waters around them. They would be an integral part – in fact a key part - of the MITS. Charging methodology is supposed to be forward looking and the Council submits that the Workgroup should give more explicit recognition to this than it appears to have done.

Q	Question	Response
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	The Council's overall view is that the islands, like the periphery of the UK mainland, represent the future for the power generation from renewables that the UK will increasingly need. A transmission methodology which sends locational signals counter to this is not helpful and is not facilitating the necessary re-orientation of the UK transmission network. The Workgroup has done a great deal of complex work, but within the constraints of the existing charging methodology. Thus in the Council's view there needs to be a) a much greater recognition of overall strategy for achieving a sustainable energy future for the UK; b) recognition of the characteristics of different renewables technologies, the potential for counter-correlation based on these characteristics and on the differing local conditions of different project sites, through further development of the Heriot Watt research; c) an acceptance of the spirit of the EU directive on avoiding disadvantaging islands and peripheral areas in the setting of transmission charges, and hence acceptance an islands expansion factor which incorporates some constraint on the disparity between charges for the islands and those for the adjacent mainland areas.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	No comment.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	No comment.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	Not applicable.
Do you have any other comments?		

Q	Question	Response

RenewableUK
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Web: www.renewable-uk.com
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Date: 15th January 2013

To: (by e-mail)

cusc.team@nationalgrid.com

From: (by e-mail)

zoltan.zavody@renewableuk.com

Dear Sir/Madam,

RenewableUK consultation response
CMP 213 Project TransmiT TNUoS Developments

Summary

RenewableUK welcomes National Grid's consultation on the discussions of the CUSC Working Group. Our overall thinking is as follows:

- **The process and the content of proposals should be considered in the context of the original rationale for the review of transmission charging, namely to facilitate the timely move to a low-carbon energy sector.**
- **There is a need for an ongoing and open assessment of the impact of proposals before decisions are made, not least to avoid unintended consequences.**
- **The work should aim for an implementation date of 1st April 2014, in recognition of the need for a timely outcome that facilitates achievement of the 2020 renewables target and allows congruence with the development of European policy on charging.**
- **We particularly support exploration of a year-round load factor with no peak security; and of the inclusion of 100% HVDC converter costs in the residual.**
- **There is a need for close linkage between this work and work to develop a Government support scheme for island renewables.**

Introduction: RenewableUK, The Work Group Consultation and Rationale

RenewableUK is the trade and professional body for the UK wind and marine renewables industries. Formed in 1978, and with over 660 corporate members, RenewableUK is the leading renewable energy trade association in the UK, representing the large majority of the UK's wind, wave, and tidal energy companies. The association's response aims to represent these industries, aided by the expertise and knowledge of our members.

RenewableUK represents developers from across the UK, from the south of England to the north of Scotland and the Scottish islands, all of whom may be affected differently by various proposals for transmission charging. RenewableUK's vision is of renewable energy playing a leading role in powering the UK's homes and businesses. As such, this response aims to reflect what best serves the long-term deployment of renewable generation as a whole.

Our interest aligns with the original objective of Project TransmiT, namely: "to ensure that arrangements are in place that facilitate the timely move to a low carbon energy sector, whilst continuing to provide safe, secure, high quality network services at value for money to existing and future customers."

While the CUSC Working Group is obliged to assess modification proposals against CUSC criteria, Ofgem states that its direction should be read in the context of the original reasons for the TransmiT SCR. As such, we believe there is validity in referring to these when assessing which proposals to pursue. In particular, proposals should be considered in terms of their compatibility both with a timely move to a low carbon energy sector, and with Ofgem's statutory duty to protect the interests of both current and future customers.

Since 2020 is the legally binding target for renewables deployment, the timeliness of an outcome to the CUSC WG process should be assessed in the context of helping to achieve this target. The original discussions were also concerned with congruence with, and leverage across to, the evolving European charging debate. This opportunity should not be missed by an overly protracted process that, if it runs long enough, would eventually be overtaken by decisions in Europe.

Our response is structured according to the question categories in the consultation, but we take the questions on implementation and transition first, as these are crucial to the framework for the decision making process.

The Proposed Original and Applicable CUSC Objectives

We believe the proposed Original better facilitates the Applicable CUSC objectives on two counts: a) the promotion of competition; and b) cost-reflectivity. These apply to greater or lesser extent to all three areas under investigation, as follows:

On sharing, renewables and in particular wind generators do in general share assets. Recognising this sharing therefore opens up the generation market to more (renewable) generation; and reflects more accurately the costs of transmission. The Original balances the relevant factors of transparency, accuracy, and certainty.

On HVDC, we welcome the proposal to consider HVDC costs but believe this technology should be placed on an equal footing with AC, thereby opening up competition amongst generators that might more easily connect through HVDC; and promoting cost-reflectivity by considering the component costs and benefits of HVDC.

On island charging, the facilitation of generation on the islands allows more entrants into the generation market, particularly in these remote areas. The cost-reflectivity assessment is less clear, and we believe this should be balanced by the need for a stable and predictable charging regime.

In summary, RenewableUK supports the consideration of all three areas addressed in the Original. This is not to say at this stage that all the solutions proposed in the Original, and their combination, are the most effective, and we discuss some of the issues further in our response below, including the need for an ongoing assessment of impacts.

Questions 16-17: Implementation and Transition

Our chief concern is that it is very difficult to understand the impact of the proposals on the generation sector, with particular focus on the renewables industry. While it is important to understand principles relating to transmission charging, CUSC parties are also concerned about the impact on individual projects, and then the impact across both current and future generation. Such issues will be addressed and evidence provided as part of a final Impact Assessment, but this will be after a decision has been made on the proposal(s) to take forward. As such, in terms of how the CUSC process works, opportunities for consultation and an ability to input into the working group's discussions will be limited. Within our sector there is a concern that there may be a range of unintended consequences that then need to be addressed.

RenewableUK's position is necessarily to support proposals that facilitate the accommodation of renewable generation on the system, consistent with the original aims of TransmiT. It therefore needs to be possible to assess the proposals against this criterion.

Furthermore, a criterion for CUSC methodology is that it "facilitates effective competition in the generation and supply of electricity." Competition is best served by transparency and simplicity, whereby generators understand and can respond to price signals.

For these reasons, we support ongoing and open assessment of the impact of the CUSC WG proposals at an early stage and far ahead of the eventual regulatory impact assessment, in order for an informed assessment to be possible. We would urge National Grid and the Working Group to look at options for active and open communication with wider industry, including use of the NG website to include updates of progress, as well as provision of more stakeholder discussion days (such as those held in December 2012) prior to the finish of the Working Group deliberations.

Balanced against this, our other chief concern is that the process will be further delayed. The Significant Code Review report that led to Ofgem's Direction "urge[d] industry to expedite this process and submit a final CUSC amendment report … in a timely manner to ensure benefits are realised as quickly as possible." It also pointed out that the standard CUSC process takes around six months to complete. Protracted delays could eventually come up against the commencement of European legislation from 2014 onwards, and arguments that there is no longer any point in implementing Improved ICRP. Finally, with extensive Round 3 offshore development from around 2017 onwards, it is important that there be a period of charging stability some time before this.

We understand that there are tensions between calling for wider industry engagement and maintaining a strict timetable. However, we wish to emphasise that we are keen that the work should aim for the implementation date of 1st April 2014, and arguments for “further investigation” should not undermine this. We would consider supporting the Working Group, and subsequently, the CUSC Panel, being able to recommend a shorter than usual notice period for implementation, with opt-outs provided to existing generators so that they can manage the risks of transition to a revised methodology.

Questions 1-5: Sharing

We support sharing of some description. Wind generators do in general share assets without this being factored into the charging regime, and this means they have been and are being overcharged. There are many potential solutions, none perfect, but change is needed or wind will continue to be disadvantaged. We believe the calculation methods that warrant exploration are methods iii-v.[1] We do not see how methods i and ii would be compatible with the aims of this work.

We support further consideration of the Original proposal for sharing. The introduction of a peak security tariff may have vastly different consequences for renewable generators in the north and south, and this needs exploration. The impact of not recognising renewables’ contribution to peak demand in negative charging zones results in renewables projects being worse off than conventional generators under IICRP because they no longer benefit from the from the negative peak demand tariff. The Redpoint analysis commissioned by Ofgem also shows significant additional costs to renewable projects in England and Wales where year-round tariffs increase under IICRP compared to the status quo.

We also support a further exploration of the option to use the existing single background Transport model but with charges based on annual average load factor not capacity. In other words, sharing would be based on the total load factor rather than the load factor applied only to the year-round element. Further discussion is needed on how this load factor would be calculated. We understand this option is covered by the existing proposals for Alternatives,[2] otherwise RenewableUK would propose it formally.

[1] Table 4, page 10.

Questions 6-9: HVDC Circuits

We support the exploration of an Alternative that includes 100% of HVDC converter costs in the residual in the same manner as AC substations.[3] Decisions should not have different outcomes for generators just because different grid technology is used, if the overall cost and benefit to the system are the same. While we understand that the Working Group has sought to understand the similarities and differences between AC and HVDC, we would stress an additional element, which relates to transparency and predictability of charging. While the methodology seeks to apportion the costs of transmission, and the overall cost burden will not be affected by changes to the methodology, different treatment of elements such as substations and converters will impact on generators. Thus decisions taken by Transmission Operators to develop infrastructure using HVDC rather than AC will lead to increasing costs (compared to the AC alternative) for certain generators. This does not seem proportionate or equitable treatment of one group of generators in comparison to another. This would distort competition, and is also likely to disadvantage a large proportion of low-carbon development.

Questions 10-15: Island Connections

We support the need for a support scheme that facilitates the deployment of low carbon energy in the islands. We support the consideration of sharing on the islands. We note, however, that this will be insufficient by itself to remove barriers to connection in the islands. The UK Government is working separately on this issue, but there needs to be close linkage between the two programmes of work. As this process is led by the UK Government, there is a need for the Working Group and CUSC Panel at least to understand the timing of this parallel process, as well as likely options under discussion by public bodies for supporting island generation. We would urge the Working Group to invite a relevant official to attend and present to the Working Group, and vice versa.

It is important that the CUSC process not be bogged down by proposals for a specific issue such as islands charging. However, even as support schemes are discussed, some form of predictable charging methodology is needed for sub-sea cables to the islands. In its deliberations we would urge the Group to take into account

[2] Item iii, Table 13, page 32.

transparency and predictability as an important component of charges for island based generation. Clearly transmission charges for island generation will be higher. It is therefore very important that the charging base is not volatile and is transparent, as ability of such generators to absorb additional costs (e.g. future transmission charging increases) may be very limited.

Question 18: Governance

We do not wish to raise any new Alternatives, but would particularly like to express our support for further exploration of a year-round load factor with no peak security; and of the inclusion of 100% HVDC converter costs in the residual. We understand this option is covered by the existing proposals for Alternatives,[4] otherwise RenewableUK would propose it formally.

We trust this submission is helpful, and we look forward to working with you towards a timely and transparent outcome.

Yours faithfully,

Zoltan Zavody
Grid Policy Team

[3] Page 105 a) i).
[4] Item iii, Table 13, page 32.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	*Gaynor Hartnell ghartnell@r-e-a.net 020 7925 3578*
Company Name:	*Renewable Energy Association*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The proposed methodology is an improvement on the current methodology given the revisions to the SQSS that have been implemented that recognise the different characteristics of different types of generator and the resultant different amounts of transmission that each justify investing in. Where we prefer one of the options to the original in any area we mention this in the detailed comments below.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We think that overall the original does better facilitate the applicable CUSC Objectives compared to the status quo. In particular: In terms of facilitating effective competition the proposal is better than the status quo as recognising the different costs imposed on the transmission system by different types of generator and charging them accordingly it allows fairer competition between generators of different types. The same reasoning applies to objective b better reflecting the costs that are incurred by the transmission licensees. Objective c is better met as the current methodology makes no provision at all for taking account of the cost of dc circuits that run in parallel with the ac network. *For reference, the Applicable CUSC Objectives for the Use of*

	System Charging Methodology are: *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	Yes we think that on the whole a date of April 2014 would be appropriate for implementation.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	There does not appear to have been much consideration in the section proceeding this section into the issue of charging for local circuits where there may or may not be diverse types of generation using these circuits. We are aware that the section of the SQSS dealing with the connection of generation is under review and it may be best to revisit issues associated with the sharing of local circuits after this has been completed. In terms of charging for the use of the MITS the group has clearly spent a considerable effort looking at the effect of the variation in generator types on sharing of transmission. Whilst there are undoubtedly other options that could be considered we do not have any specific alternatives that we would advocate.

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	We think that the Workgroup has reviewed a sufficient number of options in sufficient depth and we would not advocate further analysis. On balance whilst we feel that although there is much merit in using the fixed load factors that are used in the SQSS, we are persuaded that using the actual five year historic load factors also has merit.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No. Our view is that this a very simple matter – as TNUoS charges are meant to be reflective of the cost of building transmission assets, the peak Security element for intermittent generation of any type should be indexed to whatever is used in the SQSS.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	The Workgroup has certainly considered a large variety of options for the sharing element of the proposal and whilst there are certainly others that have not been considered we do not advocate considering any other one. We note the attention to differences between how the system is planned and how ICRP calculates charges and recognise that this is a weak point of ICRP. If however one is sticking to the ICRP philosophy i.e. that each incremental MW flowing should be charged as an extra MW of capacity then allocating costs between the peak security and year round flows on the basis of the relative flow in each case is more consistent with this than defining each circuit as reinforcement driven by either one or the other case. ICRP assumes that an extra MW flow demands an extra MW of investment and so this is the case for both the peak demand and the year round flows – each circuit should therefore be apportioned between these cases, if consistency with the ICRP philosophy is to be maintained.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	As a general rule the charging methodology should follow the system planning philosophy as far as possible. With a couple of exceptions noted above (and leaving aside the issue of how cost reflective the basic ICRP methodology is) the proposed methodology does that.

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	There may be possible other options but we do not advocate consideration of any specific further ones.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	As above, whilst there are other methodologies we do not advocate consideration of any further ones.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We do not wish the workgroup to consider any specific further options.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	We think that the original proposal is satisfactory although can see merit in reducing the cost of hvdc links that parallel the ac network by the cost of a quadrature booster that would give a similar degree of controllability for so long as the cost of quadrature boosters are not included in the locational element of TNUoS charges.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	There are no doubt other options but we do not wish to promote them. We think that a local / wider split should be maintained on islands whilst it is being maintained on the rest of the system. As stated earlier the issue of sharing on local circuits should follow from the approach in the SQSS.

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes. We would advocate dividing the circuit length by 1.8 where the island substation is part of the MITs but it only enjoys essentially a single circuit connection to the mainland.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes. Our view is that anticipatory changes would have to apply system wide and anticipate a MITs node becoming a local one as well as vice versa. In general we feel that such an arrangement is likely to be problematic.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We do not have any other proposals or options that we would like to be considered.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	In general islands should be treated like the rest of the system with the reduction in length of a connection to the mainland by 1.8 where it is a single link. Sharing proposals for local circuits should follow what is laid down in the SQSS.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We think that implementation should be in April 2014 if a final decision is made by Ofgem by the end of September 2013, otherwise from April 2015 (assuming a final decision by the end of September 2014).

Q	Question	Response
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Our view is that following the Ofgem decision generators should have up to 20 working days to give notice to reduce their TECs from the time when the new charging methodology is to be introduced. For example if Ofgem decides on 15th September 2013 that the new methodology should be introduced on 1st April 2014 generators should have 20 working days from 15th September 2013 to make any adjustments to their TECs post 1st April 2014 without penalty.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No *If yes, please complete a Workgroup Consultation Alternative Request form, available on National Grid's website, and return to the above email address with your completed Workgroup Consultation response proforma.*
Do you have any other comments?		No.

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The CUSC Team
National Grid
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Our Ref: EN01-003502

15 January 2013

Dear CUSC Team,

Re: RES UK&I Response to CMP213 Workgroup Consultation

Renewable Energy Systems (RES) welcomes the opportunity to respond to the "CMP213 Project TransmiT TNUoS Developments" workgroup consultation document published 07 December 2012 ("the Workgroup Consultation"). As a workgroup member, RES has contributed to discussions that have given rise to the progress to date as outlined in the Workgroup Consultation and the views set out below should reflect those contributions. RES is comfortable that the Workgroup Consultation is a fair reflection of the material considered and the key points of debate.

Sharing

Q1: Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?

In light of the implied guidelines set by the preceding work conducted under Project TransmiT and by the Ofgem SCR direction, RES considers that the Workgroup has considered as broad a range of geographical charging structures as could reasonably be expected. RES notes the comment on paragraph 4.61 which states that "*The proposer currently believes that the simplicity of a simple generator's annual load factor based approach outweighs any cost reflectivity benefits that a more complex approach taking into account generation plant diversity could bring*". In light of the evidence considered and debate completed to date, RES is in agreement with this statement.

Q2: Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.

RES agrees that the Workgroup has been thorough in its consideration of options for methodologies of calculation of ALF. Taking into account the intended purpose of ALF, i.e. an adjustment to reflect long term network sharing, RES considers, at this stage, that the methodology based on five years of historical output, as included within the original proposal, represents the most appropriate way forward.

Q3: On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?

RES would not seek to add views in addition to those set out in the consultation. RES would support the approach outlined in the original proposal.

Q4: Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the sharing aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

RES considers that the working group has cast its net suitably wide in considering sharing options and would not, at this stage, propose any additional options.

Q5: What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?

Throughout the Project TransmiT process, RES has supported a move away from purely capacity based charging of TNUoS for generators on the grounds that it is not reflective of transmission owner investment practices nor of actual usage of transmission system assets. RES therefore welcomes the debate around an extensive range of alternative approaches to generator TNUoS charging that better reflect actual development and usage characteristics thereby arriving at a more appropriately targeted Wider TNUoS charge. Going forward, RES is keen to see how sharing options can be refined into potential methodologies which represent an appropriate balance between cost reflectivity, simplicity, transparency and stability. As noted in our response to Q1, at this stage, RES considers the approach to sharing proposed in the original to represent the optimum balance between these factors.

HVDC Circuits

Q6: Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.

RES considers that the workgroup has been thorough in considering possible methodologies for calculation of HVDC expansion factors but is of the view that there is further debate to be progressed in order to reach an appropriately considered conclusion. RES does not agree with the proposal to include the cost of the HVDC converter station in the HVDC expansion factor on the grounds that it would bring about discriminatory treatment against generators connected behind an HVDC link relative to generators not in such a position. RES considers that the arguments raised in relation to AC equivalence and also in relation to equivalence with treatment of onshore fixed plant items such as quadrature boosters and substations substantiate this position. However, more fundamental is the argument that it seems unreasonable and discriminatory to burden certain generators connected behind HVDC circuits with a significantly higher wider TNUoS charge as a result of a TO decision on technology type, a decision that is presumably taken on grounds of transmission system economy and efficiency rather than generator preference.

Q7: Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?

RES is content that the Workgroup has considered an appropriate range of options for modelling of HVDC circuits in the DC load flow model. At this stage, RES would support a methodology for calculation of equivalent impedance using the flows across the average of all boundaries bypassed by the HVDC circuit (as set down in the original) because it represents a more complete reflection of the benefit provided by that HVDC circuit relative to the single most constrained boundary approach discussed in the workgroup.

Q8: Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the HVDC circuit aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

RES considers that the workgroup has adequately considered options in relation to HVDC circuit operational cost and security.

Q9: What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?

RES would not, at this stage, wish to add any points over and above those points raised in response to Questions 6, 7 and 8.

Island Connections

Q10: Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?

RES notes the extensive review of issues associated with the current definition of MITS GSPs and local circuits that has been conducted by the group and would not propose additional areas of investigation.

Q11: Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?

RES would not propose further alternatives in relation to security factor at this stage.

Q12: Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.

RES would not propose further alternatives at this stage but would reiterate its support for recovery of the cost of HVDC converter stations through the residual charge rather than through the expansion factor as proposed in the original.

Q13: Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.

RES considers that the Workgroup has adequately considered the issue of anticipatory application of the MITS definition to island nodes and would not propose further issues to be considered at this stage.

Q14: Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

RES would not propose further Island alternatives at this stage.

Q15: What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?

RES agrees with the overall thrust of the discussions in the Workgroup, namely that it is difficult to justify changes to the TNUoS charging methodology in a manner consistent with CUSC relevant objectives for the specific circumstances of Islands.

Implementation and Transition

Q16: The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.

At this stage, RES would support option 2 "implementation from 1st April 2014" as the optimum balance between timely implementation and opportunity for due consideration.

Q17: The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.

RES would not propose a specific transitional reduced notice period for TEC reduction or termination at this stage and considers that the requirement for one off arrangements will become clearer once the materiality of the proposed options becomes clearer.

Governance

Q18: Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?

RES would not wish to propose a specific Workgroup Consultation Alternative Request.

Yours sincerely,

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Swindon, 15/01/2013

CMP213 Workgroup Consultation - RWE Response

Dear Cusc Team

We welcome the opportunity to comment on the CMP213 Workgroup Report. This consultation represents an important stage in the evolution of the GB transmission charging regime.

We note the considerable work undertaken by the working group. This includes the development of a large number options and variables which may result in alternatives that better meet the CUSC objectives. However, we have a number of concerns on progress to date including the following:

- The process completed by the Working Group to date is flawed in that group has not fulfilled the terms of reference as set out by the CUSC Panel on 9th July 2012 particularly with respect to paragraph 5 (k) in the scope of work with respect to "consider and undertake appropriate economic analysis including the impact on current and future customers on a national and regional basis". The Working Group Report does not include any assessment of the impact on the proposal on customers whether existing or future customers.
- Further work is required on the original modification proposal to clarify the arrangements and the potential options that remain in or out of scope. For example, there are a wide range of different approaches towards the issue of sharing particularly with respect to the assessment of load factor including the potential development of a "diversity" factor.
- It is very difficult to evaluate objectively the potential options from the information presented in the report. This reflects the absence of both qualitative and quantitative criteria to determine the relative merits of the options and detailed information in the form of evolved tariffs and the potential impact on generators and customers. This makes it impossible to determine whether competing options better meet the CUSC objectives.
- Substantive work is required both to define a small number of alternatives and to provide the detailed analysis that would enable market participants to form a view on the relative merits of the proposals. It is essential that such work is subject to further industry consultation prior to consideration by the CUSC Panel.

...

- We do not believe that it is appropriate for an impact assessment to be undertaken during the Code Administrator's Report phase under the CUSC modification process. We fail to see how market participants and the CUSC Panel can possible come to a view on the proposals against the relevant CUSC Objectives without such an assessment during the initial working group phase.

In the absence of any detailed assessment, we can only rely on work conducted outside the modification workgroup to provide our views on the proposals. Work by Redpoint as part of the Ofgem Significant Code Review has already indicated the negative customer welfare impact of the "improved" ICRP methodology[1] particularly in relation to constraint costs and transmission investment. Further work from NERA[2] indicates that "improved" ICRP will significantly impact on customer welfare through effects on the marginal costs of electricity generation.

Whilst neither report provides a definitive view of the emerging CMP213 proposals in the Workgroup Report, we can only conclude that "improved" ICRP as set out in the original proposal will not better meet the CUSC Use of System Charging Objectives[3]. In particular:

- The proposal fails to facilitate the competition in the electricity market (CUSC UoS Charging Objective (a)) given the effects on the marginal costs of generation in the GB market and the lack of cost reflectivity when compared with the current arrangements;
- The relationship between Incremental constraints costs and Annual Load factor has not been demonstrated across the GB system for the current plant disposition under CMP213 and furthermore this relationship does not hold for future years as demonstrated in the report by Bath University[4] The CMP213 proposal with respect to sharing does not, therefore, better meet CUSC UoS Charging Objective (b);
- The locational signals inherent within the methodology have a detrimental impact on existing high and low load-factor power stations in southern Britain while incentivising the location of new low and high load-factor plant behind constraints. The CMP213 arrangements are not more cost reflective when compared to the current arrangements and do not, therefore better meet CUSC UoS Charging Objective (b); and

[1] Ofgem transmission charging arrangements: Significant Code Review Conclusions, 4th May 2012
[2] NERA Report "Project Transmit- Modelling the Impact of Improved ICRP", 12th October 2012 can be found at http://www.nera.com/67_7953.htm

[3] CUSC Use of System Charging Objectives: (a) that compliance with the connection charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (C) that, so far as is consistent with sub-paragraphs (a) and (b), the connection charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses

[4] Op cit

- The arrangements are not compatible with emerging thinking on transmission charging within the European Target Model. Consequently we do not believe that the proposal better meets CUSC UoS Charging Objective (c).

Potential Variant
We believe that in addition to the options under consideration a potential variant should be developed based on a cost reflective forward looking charging methodology for the calculation of generation load factors. The methodology should utilise a forecast of nodal generation that reflects the background (peak and year round) transmission conditions. In effect the model will provide a forward looking assessment of the potential use and sharing of the GB transmission system to enable the calculation transmission charges that reflect the costs of efficiently incurred transmission investment and cost recovery of existing network assets.

The answers the detailed questions in the consultation document are included in the pro forma response submitted separately.

If you wish to discuss any aspect of our response, please do not hesitate to contact me.

Yours sincerely

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CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	*Please insert your name and contact details (phone number or email address) Bill Reed; bill.reed@rwe.com, 01793893835*
Company Name:	*Please insert Company Name* RWE Supply and Trading GmbH, RWE Npower plc, Great Yarmouth Power Ltd, Npower Cogen Trading Ltd, Npower Direct Ltd, Npower Ltd, Npower Northern Ltd, Npower Northern Supply Ltd, Npower Yorkshire Ltd, Npower Yorkshire Supply Ltd, RWE npower renewables, a wholly owned subsidiary of RWE Innogy GmbH
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We note the considerable work undertaken by the Workgroup. This includes the development of a large number of options which may result in alternatives that better meet the CUSC objectives. However we are concerned that since neither the CMP213 original proposal nor any of the alternatives have been properly defined there is no modelling work to examine the effects of these proposals and the impact on the wider electricity market including existing and future customers. Consequently it is very difficult to comment meaningfully on the consultation. In addition, it is difficult to assess whether the theoretical models developed by the Workgroup could lead to inefficient outcomes with major unintended consequences for transmission system development. Given the complexity of this CUSC modification, we believe that industry should be given the chance to comment on defined models, their effects on future tariffs and the market in general, the associated impacts and implementation issues before the final legal drafting consultation takes place. We have a number of concerns on progress to date by the Workgroup including the following: • The process completed by the Workgroup to date is flawed

	in that group has not fulfilled the terms of reference as set out by the CUSC Panel on 9th July 2012 particularly with respect to paragraph 5 (k) in the scope of work with respect to "consider and undertake appropriate economic analysis including the impact on current and future customers on a national and regional basis". The Workgroup Report does not include any assessment of the impact of the proposal on customers whether existing or future customers. • Further work is required on the original modification proposal to clarify the arrangements and the potential options that remain in or out of scope. For example, there are a wide range of different approaches towards the issue of sharing particularly with respect to justification and interpretation of the National Electricity Transmission System Security and Quality of Supply Standards (NETSSQSS) findings and in particular the GSR009 implementation, the assessment of load factor as a proxy for incremental constraint costs, the potential development of a "diversity" factor on a cost reflective basis and the nature of derived historic factors for future transmission charges. • It is very difficult to evaluate objectively the potential options from the information presented in the report. This reflects the absence of both qualitative and quantitative criteria to determine the relative merits of the options and detailed information in the form of evolved tariffs and the potential impact on generators and customers. This makes it impossible to determine whether competing options better meet the CUSC objectives. • Substantive work is required both to define a small number of alternatives and to provide the detailed analysis that would enable market participants to form a view on the relative merits of the proposals. It is essential that such work is subject to further industry consultation prior to consideration by the CUSC Panel. • We do not believe that it is appropriate for an impact assessment to be undertaken during the Code Administrator's Report phase under the CUSC modification process. We do not see how market participants and the CUSC Panel can possibly come to a view on the proposals against the relevant CUSC Objectives without such an assessment during the initial Workgroup phase. In the absence of any detailed assessment, we can only rely on work conducted outside the modification workgroup to provide our views on the proposals. A study by Redpoint as part of the Ofgem Significant Code Review has already indicated the

	negative customer welfare impact of the "improved" ICRP methodology[1] particularly in relation to constraint costs and transmission investment. Further work from NERA[2] indicates that "improved" ICRP will significantly impact on customer welfare through effects on the marginal costs of electricity generation. In addition, the dual background approach to represent approximately the dual criteria approach of the NETSSQSS is flawed, and historic annual load factor alone cannot represent all the factors which determine the level of constraints and where they occur on the GB electricity system[3]. In this context GSR0009 under the NETSSQSS introduced the concept of "dual criteria" when assessing the transmission system capacity based on a demand security criterion whereby peak demand can be met without intermittent generation and an economic criterion that requires sufficient transmission capacity to enable all types of generation to meet varying demand levels based on a cost benefit analysis that reflects an economic and efficient trade-off between constraint costs and transmission investment. This dual criteria approach enables the peak load scenario to be overlaid by the cost benefit analysis to identify economic and efficient transmission investment. However the CMP213 approach based on a "dual background" (peak and year round) rather than the dual criteria approach results in two separate charges which are then integrated into the annual charges. While we recognise that there are important principles related to the alignment of the charging arrangements with the NETSSQSS principles, we do not accept that it follows that the charging arrangements have to adopt the same methodology as the arrangements for the design of the transmission system. We recognise that there is an important trade off between transmission investment and constraints. Under the current arrangements it is clear that the transmission owners will only invest in economic and efficient transmission assets that reflect use of the system. Consequently the TEC-based charges reflect the recovery of the capacity based investments and not the efficiently incurred constraint costs implied through the application of the NETSSQSS. Indeed the fact that the costs of constraints are socialised through BUSUoS demonstrates a divergence between the NETSSQSS and the charging arrangements. Furthermore, the socialisation of BSUoS with respect to the

1 Ofgem transmission charging arrangements: Significant Code Review Conclusions, 4th May 2012
2 NERA Report "Project Transmit- Modelling the Impact of Improved ICRP", 12th October 2012, http://www.nera.com/67_7953.htm
3 Furong Li et al, (Forthcoming), "Year round system congestion costs – Key drivers and key driving conditions", University of Bath

	incremental costs caused by the connect and manage arrangements clearly create a number of issues for the evaluation of CMP213. In particular we believe that CMP213 must take into account an optimised version of transmission investment and explicitly address the issue that the actual network configuration may not be not compliant with the NETSSQSS as a consequence of connect and manage. In addition the charging methodology must also take account of the advanced connection dates for connect and manage generators which give rise to additional early constraint costs. In principal the current charging arrangements reflect the fact that less wider transmission assets are being built for low load factor plant. However the NETSSQSS dual background connection methodology together with connect and manage arrangements already result in incremental constraint costs. CMP213 may lead to further constraints as generators respond to the less cost reflective locational signals. This will result in less economic transmission investment when compared with the current charging methodology. Further consideration is also required of the effect of connect and manage arrangements on exacerbating costs in constrained areas under the "improved" ICRP methodology (as indicated in the Redpoint work[4]). We note that since these costs are already socialised, then any increase in such costs effectively increases the cross subsidy and discriminatory treatment in favour of certain users. Therefore these effects must be quantified and appropriately assessed (particularly in relation to additional state aid considerations).
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);*

[4] Op Cit

	(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. The large number of options and variables included in the Workgroup document makes it difficult to determine whether the CMP213 original or any options for alternative better meet the relevant CUSC objectives. In particular the lack of a detailed impact assessment suggests that it is difficult to provide any determination in relation to the CUSC objectives. Given information provided elsewhere by Redpoint and the published NERA[5] analysis we believe that the original version of CMP213 may not better meet the CUSC objectives. In particular: • The proposal fails to facilitate the competition in the electricity market (CUSC UoS Charging Objective (a)) given the effects on the marginal costs of generation in the GB market and the lack of cost reflectivity when compared with the current arrangements; • The relationship between Incremental constraints costs and Annual Load factor has not been demonstrated across the GB system for the current plant disposition under CMP213 and furthermore this relationship does not hold for future years as demonstrated in the report by Bath University[6] The CMP213 proposal with respect to sharing does not, therefore, better meet CUSC UoS Charging Objective (b); • The locational signals inherent within the methodology have a detrimental impact on existing high and low load-factor power stations in southern Britain while incentivising the location of new low and high load-factor plant behind constraints. The CMP213 arrangements are not more cost reflective when compared to the current arrangements and do not, therefore better meet CUSC UoS Charging Objective (b); and • The arrangements are not compatible with emerging thinking on transmission charging within the European Target Model. Consequently we do not believe that the proposal better meets CUSC UoS Charging Objective (c).
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We believe that further consideration of the implementation dates is required given the need for the completion of an impact assessment of the original and any potential alternatives by the Workgroup and the likely effects such a change will have on the electricity markets including assessment of lead times for

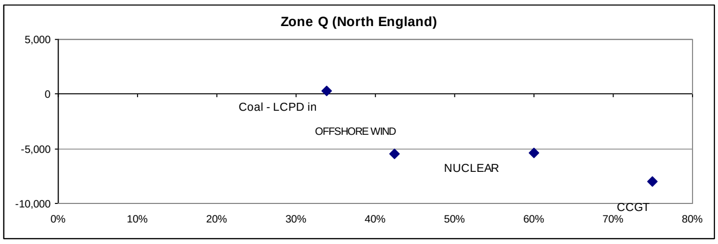
[5] Op Cit
[6] Op cit

	electricity power purchase arrangements and the proposed capacity mechanism The impact on existing and previously sanctioned plant should also be taken into account. Transitional arrangements (including the role of grandfathering) should be considered as a means of mitigating regulatory risk. If this is not considered, it may become difficult to obtain financing in future. We believe that this is a particular issue for renewables projects given the large number of projects in development

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	We do not believe the that workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits. The work undertaken by the group with respect to options for the charging structures in areas dominated by one type of generation provides an important insight into the cost reflectivity of the sharing arrangements outlined under CMP213. What has become clear is that some areas of the transmission system are dominated by certain generation types. This means that in considering the cost reflectivity, any sharing arrangements must take into all account the different characteristics of generators connected to the GB transmission system in these areas. These characteristics are related to the generators ability to self dispatch when the market price is favourable, which correlates with demand on the entire system, and also the Bid and Offer prices submitted in the market. Specifically, in some exporting areas, the bid price is one of the main driving factors for constraint costs for some specific plant types. This means that if the transmission system is constrained at times when dominated by intermittent generation output, then the constraint costs are high. It is important to note that the adverse effect of this type of generation on constraint costs is not dependent on its yearly out-turn Annual Load Factor, but on its correlation with other generators in the same area. The diversity of zones dominated by different types of generators significantly increases the complexity of the suggested arrangements when compared to the uniform approach to entry capacity under the current ICRP methodology. We believe that this complexity is reflected in the range and extent of the different approaches towards sharing options considered by the Workgroup, some of which may result in alternatives. Our preferences is to synthesise the options for sharing into a variant based on a forward looking cost reflective load factor assessment that utilises representative forecast of generation output under the relevant transmission network configurations (peak and year round). Such an approach would enable the charging arrangements to have due regard to future changes in generation and the transmission network.

Q	Question	Response
		The essence of this variant would be to calculate a factor which effectively multiplies the signals derived for a “year-round” scenario to account for diversity and other factors. Note that we are only proposing this as a variant rather than an alternative to CMP213 since the original proposal must use just two backgrounds, (peak and year round).
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated? Are there any areas that you think may need further development? If so, please specify along with an associated justification.	The workgroup has not sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. We note the comprehensive consideration of load factors across transmission boundaries and note that the relationship between constraint costs and load factor may not be a simple linear relation (see for example, Figure 30 and 31 in the Workgroup consultation document). This is illustrated in the graph below for the North of England boundary.  Further work is, therefore required to consider the relationship between constraint costs and load factor. In particular consideration should be given to forward looking sharing factors based for example, on the prospective contracted TEC a security constrained dispatch model for the respective background scenario and representative relationships between load factor and constraints. We believe that such an approach would be capable of delivering more cost reflective tariffs than any approach based on historic analysis.

Q	Question	Response
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	We believe that intermittent generation should be exposed to a Peak Security element of the tariff where it is cost reflective to do so. In this context the Workgroup should investigate the definition of peak security. The key question is whether it means one single half hour when the yearly demand is at its absolute peak, or a time period of the year when the daily peak demand is expected to be within say 95% of the out-turn absolute peak demand. This is important, since at the absolute peak demand level, generation availability is usually high enabling the System Operator to optimise the flows on the network and accommodate high levels of intermittent output, and in particular in importing areas. If “peak” means a period from say November to February, then it is clear that intermittent will be generating at peak and will contribute to peak security. In addition if the penetration of intermittent types of very high, and at diverse locations on and off shore of the UK, then it can be expected to be generating significant volumes at all times. It is appropriate for intermittent generation to be exposed to a Peak Security tariff where such generation is capable of contribution to generation output at the peak. In this context it is important that conventional thermal intermittent generation such as OCGTs and hydro schemes are considered alongside the peak contribution from renewable technologies such as wind. Stochastic approaches should be considered by the workgroup to capture the probability of intermittent renewable technologies contributing to meeting peak demand.

Q	Question	Response
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We do not believe that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal. While we note the considerable work on sharing undertaken by the workgroup a wide range of potential options remain under consideration. It would be helpful if the potential sharing options are organised into a coherent and workable set of proposals that appropriately reflect on users the costs associated with use of the transmission system. In this context we do not believe that the sharing arrangements based on the dual background in the original proposal are cost reflective, particularly in relation to the use of historic load factors. We are more supportive of potential options that reflect prospective "diversity" and allow for capacity-based charging arrangements to reflect the transmission benefits of locating power stations in certain areas of the GB transmission system. In the context of diversity, we believe that a potential variant based on a forecast of expected output from generation and demand nodes across the network and a model that considers the prospective outcome of load flow conditions across the network in an optimised least cost approach should be developed to reflect sharing across transmission boundaries. The model would be based on the contracted TEC for each power station, the demand capacities and the expected state of the transmission network. A set of load factors would be derived for each node based on an optimised least cost dispatch model on an unconstrained basis (the "unconstrained schedule"). The model would then be rerun to identify the cost of constraints (the "constrained schedule"). The forecast costs of constraints together with the nodal costs of the transmission network would provide the basis for calculating the Transmission Use of System tariffs for the following year. We also believe that the potential variant should enable the calculation of long term tariffs (across multiple years). Such an approach would enable parties to efficiently and effectively manage the risks associated with use of system charges and would facilitate the introduction of other market reforms (such as a capacity mechanism).

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	The current TEC-based approach towards transmission charging is the most cost reflective approach to the impact of different generators on incremental network costs. Under this methodology all generators are treated on a non discriminatory basis and all generators are capable of accessing the transmission network up to the level of their TEC. If it is not possible to devise a an appropriate cost reflective methodology that reflects capacity sharing then the current capacity based arrangements are more cost reflective. It is, however, appropriate for the NETSSQSS to take into account generator characteristics in the design of the network. This results in economic and efficient transmission investment.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We note the potential options associated with the treatment of HVDC links. We believe that it is essential that the principal that the beneficiary pays for the investment should be established in relation to such assets. This implies that generators in northern Scotland should contribute a cost reflective fair share in relation to the charges for these transmission investments. We note that this may result in higher charges for generation in Scotland reflecting the fact that such users will benefit from reduced constraint costs, have more reliable access to the GB electricity market and only pay for economic and efficient investment.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	We believe that the workgroup has satisfactorily considered the all the options and potential alternatives for the treatment of an HVDC network as part of the GB transmission system.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We believe that the workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal.

Q	Question	Response
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The best way to incorporate HVDC circuits that parallel the AC network in the TNUoS charging methodology is to consider HVDC circuits as an equivalent AC circuit with an equivalent Impedance and a specific Expansion Factor for individual HVDC circuits. The calculation of the impedance is important and should be derived from the same principles which are used to justify the investment in the HVDC circuit; this should be based on the planned flows expected on each HVDC circuit where HVDC can be justified as the lowest cost option for transmission investment. The Expansion Factor should be calculated from the total cost of the HVDC scheme without the arbitrary definition of sub-station equipment to dilute the costs of the whole HVDC system. If an element of the converter costs can be justified by the System Operator as providing a benefit in operating the network over and above that offered by the usual AC system, then that element of the costs can be removed from the converter costs with a clear justification that the System Operator will gain efficiencies in voltage control, losses on the whole network. We would expect this to be reflected in an explicit reduction in System Operator operating costs.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	While we understand the arguments in favour of encouraging the development of renewable schemes in areas of high renewable potential such as the islands, we do not accept that the GB transmission charging methodology should be used as a basis for providing additional subsidy for such schemes. If a subsidy is given through transmission charges (implicitly or explicitly) it may lead to further system inefficiencies and additional constraint costs which may make it more difficult to obtain secure connections for new projects in these areas. This will inevitably lead to economically inefficient investments and increased overall cost. Consequently it is essential that the beneficiary should pay for the required transmission investment (both local and wider under the charging arrangements). We believe that explicit renewable support arrangements, particularly the proposed CFD should remain the basis for support for low carbon technologies.

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	We believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	We consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	We do not believe that the case has been made in the workgroup consultation for any change to the treatment of the island connections in the TNUoS charging methodology. We note that the links to the islands are initiated by new generation projects and in this case we believe that the beneficiary should pay for these links on a cost reflective basis. There is a limited case for sharing with demand where this may increase security of supply. However, the majority of these links should be regarded as local links with the relevant TNUoS charges calculated on the same basis as other local charges.

Q	Question	Response
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We believe that further consideration of the implementation dates is required given the need for the completion of an impact assessment of the original and any potential alternatives by the Workgroup and the likely effects such a change will have on the electricity markets including assessment of lead times for electricity power purchase arrangements and the proposed capacity mechanism. The impact on existing plant should be carefully considered. Financial investment decisions were based on the best available information at the time that those decisions were made. If transmission costs change substantially as a result of a significant change to the existing methodology this is a change that generators could not have anticipated. Consequently transitional arrangements are appropriate for existing generators. CMP213 may add considerable risk to the sector and will make it more difficult to make the case for funding for projects in future given the amount of perceived exposure to regulatory risk and even more so if transitional arrangements are not included.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	We support a transitional approach towards implementation of CMP213. Our preference is for a suitable lead time that would enable users to anticipate the proposed changes in their commercial arrangements This should as a minimum be two years from the start of the charging year (1st April) after the year in which an Ofgem decision is made to be consistent with hedging timescales in the electricity market. In addition transitional arrangements are required that enables existing generators to effectively manage the risks associated with the change over a number of years. This could be a gradual introduction of the new charges for qualifying generators over a minimum of five years after the implementation date.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	*If yes, please complete a Workgroup Consultation Alternative Request form, available on National Grid's website, and return to the above email address with your completed Workgroup Consultation response proforma.*
Do you have any other comments?		As noted in our answer to question 5, we believe that in addition to the options under consideration a potential variant should be developed with network sharing derived from a cost reflective forward looking Network Capacity Charging methodology for the calculation of

Q	Question	Response
		generation and demand TNUoS charges. The methodology should be based on an assessment of the background conditions for a prospective a charging year derived from forecast nodal generation and demand conditions for transmission conditions that are representative of the peak and year round background scenarios. In effect the model will provide the marginal prices for efficiently incurred transmission investment and cost recovery of existing network assets under the relevant transmission background. The methodology could include the following elements: • Nodal representation of the transmission system under peak and year round conditions for the relevant charging year including all network reinforcements and new investments planned to be delivered and operational in the relevant year. • An economic model for nodal unconstrained generation and demand. This model would enable an expected pattern of nodal annual load factors to be derived based on least cost dispatch. The economic model would include representation of network conditions under the background network conditions. • Generation data to complete the economic model would be based on the transmission entry capacity and the assumed characteristics of individual power stations connected to the transmission system (including marginal generation costs). Data would be derived from assumed economic and efficient generator output confirmed after consultation with market participants. • A load flow assessment based on the current ICRP methodology carried out for each node in turn under the representation of the background conditions. Incremental network requirements would be identified reflecting the conditions on the network. • An incremental MWkm would be established for each node. This would result in a range of MWkm derived from background conditions. A weighted average incremental MWkm can be derived that represents conditions on the transmission system under the peak and year round conditions. • The incremental MWkm for each scenario would be converted into tariffs. The tariffs would then be combined into the wider tariff.

Q	Question	Response
		It should be noted that under this methodology • The capacity at each generation node could be constrained by the Transmission Access Capacity; • The nature of the reference node for future background conditions should be established. This could be a single reference node. • The methodology may reflect the fact that constraint costs are socialised across all users under BSUoS charges as a result of the connect and manage arrangements. • The methodology should take into account the effects of the connect and manage arrangements on the state of the GB transmission system for each snapshot period (to avoid exaggerating the costs of constraints by including the connect and manage constraint costs in the assessment or understating the amount of transmission investment). A forward looking cost reflective charging methodology would enable the development of long term tariffs that better reflect the locational marginal costs and benefits associated with generation and demand on the GB transmission system. Such an approach would facilitate the development of GB charging arrangements that are consistent with emerging thinking on transmission charging under the European Target Model and with the proposed GB capacity mechanism.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	*James Anderson; james.anderson@scottishpower.com*
Company Name:	*ScottishPower Energy Management*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	ScottishPower believes that the Workgroup has carried out a thorough investigation of the issues raised in Ofgem's SCR Direction and of the supplementary issues raised by the CUSC Panel. We are not aware of any major issues which have not yet been addressed by the Workgroup. However, we would caution the Workgroup against bringing forward an excessive number of Workgroup Alternative Modifications as Users are seeking clarity of direction at as early a date as possible.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in*

	transmission licensees' transmission businesses. ScottishPower supports the Original Proposal and believes that it better meets the Applicable CUSC Charging Objectives as follows; Better reflecting the investment costs driven by generators' siting decisions through the Use of System Charging Methodology will improve competition and help better meet Objective (a). Better reflecting the investment costs which generators impose upon the transmission system through their operating pattern (as best reflected in their load factor) improves the cost reflectivity of TNUoS charges and better meets Objective (b). Recognising that National Grid has refined its transmission investment cost benefit analysis methodology (through SQSS GSR009), the Original Proposal takes account of this development in the transmission business and reflects this in the Charging Methodology better meeting Objective (c).
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	ScottishPower supports the proposed implementation approach and would stress the importance of striving to achieve a 1 April 2014 implementation date in order to reduce further uncertainty over future TNUoS charges.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	ScottishPower believes that the Workgroup has not yet had a full opportunity to consider the evidence presented by Heriot-Watt University (4.298 to 4.319) which indicates that even in areas dominated by intermittent generation, the total amount of transmission capacity built economically and efficiently would be less than the total installed generation capacity. Clearly the effects of counter-correlation demonstrated in this work would have to be factored into any alternative proposal in which a Sharing Factor was applied to the tariff components.

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	ScottishPower supports the use of an Annualised Load Factor (ALF) as a proxy for all the other economic parameters which determine a generating station's use of the transmission system. We remain concerned, however that the historical methodology proposed for calculating ALF does not take sufficient account of factors which significantly change a generator's future running pattern e.g. environmental legislation, extended outage (planned or unplanned due to breakdown) or other factors. We would support further work on developing a methodology which used Generators' forecast load factors followed by reconciliation post year–end. This methodology would be comparable to that used for suppliers' TNUoS forecast demand volumes which are also reconciled ex-post. Differences between forecast and actual usage values could be charged at 1.5 times the TNUoS rate with any over-recovery either being reallocated to all generation users via the Residual Charge or carried forward in the Kt factor to the following charging year.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	In planning for transmission access under SQSS GSR009, the System Operator assumes a zero contribution towards peak security from intermittent generation. Therefore, ScottishPower supports the majority view of the Workgroup that the Peak Security element of the tariff should not be applied to intermittent generation.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes. We believe that the Workgroup has thoroughly considered all relevant options and potential alternatives on the sharing aspect of the modification proposal. As stated in our response to Question 2 we believe that an Annualised Load Factor adequately reflects all the other economic parameters which determine a generator's use of the transmission system.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	ScottishPower believes that the original proposal achieves the best compromise between cost-reflectivity and additional complexity in reflecting the differential impact of generators into the charging methodology. While the use of a dual background and scaling factors adds a level of complexity to the existing charging model there are considerable benefits in improved cost-reflectivity. These benefits were quantified in the economic analysis prepared by Redpoint on behalf of Ofgem within Project TransmiT. The benefits of adding considerable additional levels of complexity through the use of a Sharing Factor has not yet been demonstrated and we believe that the introduction of this into the methodology would greatly reduce the transparency and predictability of TNUoS tariffs thus making it less practical for developers to make efficient economic decisions.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We believe that the Workgroup has considered all the relevant options from full inclusion of the HVDC Converter Stations in the expansion factor through partial inclusion to full exclusion. See our response to Question 8 below.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	We believe that the Workgroup has considered all the relevant options for modelling an HVDC circuit in the Transport Model. See our response to Question 9 below.

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	While ScottishPower has sympathy with the view that the cost elements of HVDC converter stations do not vary according to distance and should not therefore form part of the Expansion Factor, we recognise that they also form an integral part of the HVDC engineering solution. However, to the extent that elements of the HVDC converter station replicate the function of AC components such as substations and Quadrature Boosters which are not currently charged locationally, then equitable treatment dictates that these costs should also be excluded. Unless further cost analysis can be obtained, ScottishPower recommends that the percentage breakdown of HVDC converter costs identified at 5.35 and 5.44 should be used. Avoiding the need to derive a specific percentage split for each HVDC converter station would improve predictability and reduce uncertainty in forecasting TNUoS tariffs.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The existing DCLF ICRP Transport Model makes use of circuit impedance to calculate circuit flows. On the assumption that it is intended to continue to use the Transport Model, it will be necessary to calculate a notional impedance for the HVDC circuits in order to allocate a proportion of the energy flows to these circuits. Of the methodologies proposed for calculating this notional impedance, calculating the desired flow across ***all*** the transmission boundaries that the HVDC circuit relieves seems to best reflect the economic justification for investment in the HVDC circuit and is our preferred option.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	ScottishPower believes that the Workgroup has thoroughly explored the options for charging island generation nodes and that an appropriate charging methodology can be developed from the options discussed.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	We believe that where full redundancy is not provided in an island generator's connection that this should be reflected in the charging methodology whether the connection is deemed to be Local or Wider. We consider that the option of adjusting (dividing by 1.8) the Expansion Factor of the island circuit is an practical method of achieving this.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Due to their geography, the three proposed island link links will vary greatly in length and perhaps also in the nature and cost of their construction due to seabed conditions. Producing a generic Expansion Factor for radial HVDC links would therefore result in benefits for some island users and dis-benefits to others. ScottishPower supports the use of specific expansion factors which will avoid such anomalies and will provide a more cost-reflective signal to generators.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	There is no precedent for anticipatory application of changes to the transmission network in the charging methodology. The existing methodology does not anticipate the connection of generators or the completion of new transmission circuits and models the network as described at the commencement of the charging year. Anticipatory application of the MITS definition would require safeguards to ensure that the future changes (which would justify such a definition)n actually took place and thus avoid "gaming" by developers who could potentially secure lower charges through making spurious grid connection applications. It would not be practical to recalculate charges retrospectively over a number of charging years should a node fail to meet the MITS definition.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	ScottishPower considers that the Workgroup has thoroughly explored the potential options for accommodating island connections within the charging methodology. In its consideration of the various options, the Workgroup has demonstrated the need for consistent application of the same principles to both island and other long radial connections thus avoiding any potentially undue discrimination in treatment.

Q	Question	Response
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	We believe that the existing definition of a MITS node should be used to define whether an Island connection is treated as being "Wider" or Local". Expansion Factors for island connections should be calculated consistently with those for HVDC circuits paralleling the onshore transmission network (i.e. a proportion of converter station costs should be excluded). Expansion factors should be specific to each island connection to retain cost-reflectivity. The reduced level of security afforded to island generators should be addressed by adjusting the expansion factor to reflect this. Where island circuits meet the Local definition, and sharing of transmission capacity can clearly be demonstrated by the construction of a lower capacity than the sum of the generators' capacities, this sharing should be reflected in the Local element of the tariff.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	In their Direction of 25 May 2012, the Authority urged industry "to expedite this process and submit a final CUSC modification proposal report, with all the requisite justification and evidence, in a timely manner ***to ensure benefits are realised as quickly as possible***". ScottishPower therefore believes that implementation should be in as short a timescale as practicable in order to realise those benefits and therefore supports Option (2) April 2014. Although conscious of the problems introduced by a mid-year tariff changes, should this date not be achievable, we would support Option (3) mid-year 2014/15.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	ScottishPower would not support a transitional approach to implementation. In a similar way to the changes to TNUoS charging parameters being introduced at the start of a new Price Control period (see CMP214), National Grid have provided indicative tariffs and information on the potential direction of tariffs which Users should have been able to take account of in making their economic decisions. Please see our response to Question 16 above.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No.
Do you have any other comments?		No.

CUSC Team
National Grid
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA
Sent via email to cusc.team@national grid.com

15 January 2013

Dear CUSC Team

Response to CMP213 Workgroup Consultation

Scottish Renewables is the representative body for the renewable energy industry in Scotland, with over 320 member organisations. This industry is playing a crucial role in the Scottish and UK Government's efforts to tackle climate change and increase our energy security, and must continue to do so in order to cut greenhouse gas emissions by 80% by 2050.

Scottish Renewables develops policy and canvasses expert views through dedicated working groups. This consultation response has been developed from comments and recommendations made by members of the Scottish Renewables Grid Workgroup, checked and augmented by views from the wider Scottish Renewables membership.

As you will know Scottish Renewables, with Highlands and Islands Enterprise, has been involved in the Project TransmiT Working Group through its representative on the CMP213 workgroup. This response is therefore reflective of additional input and comments from those not intimately involved in this process. That is, we have not sought to repeat views already expressed through the Working Group process.

We wish to take this opportunity to acknowledge and express thanks for the enormous amount of work undertaken by the CMP213 workgroup on what continues to be a challenging and contentious issue for industry.

I trust that you find our comments helpful, and if you require clarification on any of the points made in the attached response, please don't hesitate to contact me.

Yours sincerely

Catherine Birkbeck
Senior Policy Manager – Grid & Markets

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Response to CMP213 Workgroup Consultation

Process and timescales

There is a widespread view that whilst the consultation itself is very detailed, there is not yet enough information to understand the implications and "bottom line" of the potentially likely main Alternatives.

Members were concerned that this is the last chance to comment on options, before options are very clearly defined. The general feeling was that the Working Group is not really at the Working Group consultation stage, but that time pressures have forced the consultation out.

During discussion at the Scottish Renewables Grid Workgroup, there were mixed views on how to address this. Some felt that additional consultation at a later stage would add delay that, on balance, would compromise implementation times and further delay the benefits of the Modification. Others felt that improving the quality of the Modification through further consultation could be worth some reasonable delay.

The group also therefore debated whether there might be a compromise where the process is not delayed, but where there remains further opportunity to influence the shape of the Alternatives in light of information on impacts. In that vein, Scottish Renewables would like the Working Group to consider release of preliminary impact assessment results, or at least indicative modelled tariffs, prior to submitting the Working Group report to the CUSC Panel. This could be facilitated through TCMF or via some other informal route where the information is released to industry. This would facilitate gathering wider views into the Working Group which itself would in any event be refining and finalising proposals in view of modelling work.

Further specific comments on each part of the proposals are as follows:

Sharing and diversity

Concerns described above were most acute around the Diversity options being debated for potential Alternatives. It seems almost certain that there will be a Diversity Alternative or Alternatives, but there is still a body of work to complete before it is possible to address questions such as: the direction of travel for tariffs; volatility implications when plant enter and leave a zone and other outcomes. More specifically, we accept that it can be demonstrated that relationships between load factor and constraint costs aren't uniform across the network, but we do not accept that the proposed solutions address this. They seek to take account of bid prices but do so in a way that themselves require some heroic assumptions and have not yet been tested. Therefore we are not convinced that there is an improvement in accuracy, whilst there is definitely an increase in complexity.

We are conscious that these comments also hold for island sharing proposals brought forward by EMEC, Highlands and Islands and ourselves, in so far as the proposals are not fully developed. We therefore understand the pressures the workgroup is under and the balance between consulting before or after something is fully developed. Scottish Renewables would welcome the opportunity to provide further industry comment as and when these proposals take more concrete shape.

Island expansion factors

As you will know, many industry participants remain concerned about the level of potential charges for the Scottish islands, and the targeting of cost risks onto developers (e.g. the assumption that generators need to absorb cost increases after they have placed user commitment and proceeded to build their project, as evidenced by recent events in the Western Isles).

Island developers also feel at a disadvantage to mainland developers where some cost categories are more readily fed into the residual component, but where there is a reluctance to mirror this for radial and island connections. E.g. recent cost increases for the Western Isles link have been attributed in part to discovery of more difficult ground conditions, which it is assumed will be passed through in locational charges. The costs of tunnelling on the mainland are not, however, passed through locationally, presumably in part because these costs are high and specific to ground conditions and so difficult to predict and generalise.

It's difficult to argue that generators shouldn't see a cost signal associated with the choices they make, but the islands at the moment appear captive to choices made by others at a late stage in development. This makes investment very difficult.

Whilst the level of charge is perhaps not something that the Connection and Use of System Code can address directly, relative cost reflectivity, predictability and stability do sit with the Connection and Use of System Code. Scottish Renewables therefore supports consideration of generic island expansion factors, perhaps even that remain fixed or index-linked for a particular asset rather than a price control period.

Sharing and Local / wider definitions

Scottish Renewables has participated in the development of a local sharing option for islands and is therefore naturally supportive of it. We will read others' feedback on the proposals with interest.

The local / wider debate around islands is largely one that is attached to sharing and how it applies to the islands. One concern is that islands might be dominated by one technology and that there is little sharing. Diversity attempts to address this but still has generic assumptions that do not fit the island context or indeed other circumstances that have a mix of low carbon generation with some sharing.

Another related concern is that generic assumptions on transmission investment are less likely to be applicable where there is just one single circuit connection to the mainland, and that in this instance a more specific approach is desirable. This could be addressed by a definitional change to local / wider or a different definition of sharing in the Original that doesn't use local / wider. Scottish Renewables supports the latter.

HVDC

The consultation has a comprehensive set of options for the treatment of HVDC and we don't have any major comments to add.

Process going forward

We are aware that for such a multi-faceted Modification, even simply putting together Alternatives will be a major task. It is through this process that the Working Group can influence the outcome, rather than the content, through influencing the choices (and the combination of choices) put forward to Ofgem. This is an important part of the process and it is essential that it is handled impartially and reasonably by the Working Group. Further to the point raised under 'Process and timescales', we feel that the workgroup should maintain focus on delivering outcomes that are fully developed and understood by industry and if this requires further or more analysis, any additional time required to do so should be minimised, and wherever possible, accommodated within the existing programme.

Scottish Renewables feels that each of sharing, islands and HVDC should be constructed as if they were separate Modifications so the content of one can't influence the attractiveness of another. Given the number of potential Alternatives for each one, we also feel that it is an unnecessary headache for the Working Group to have to build up one very large Modification from each of the three, and would ask the Code Administrator to consider whether it is possible to separate them for the purposes of going to Ofgem.

Summarising SR Response to specific Consultation Questions

Sharing

Q1 (geographic options considered) – we request further opportunity to shape alternatives – see above.

Q2 (sharing factor options) – we request further opportunity to shape alternatives – see above.

Q3 (peak security for intermittent generation) – no comment.

Q4 (sharing aspects) – we request further opportunity to shape alternatives – see above.

Q5 (differential impact of generators) – we request further opportunity to shape alternatives – see above.

HVDC

Q6-9 inclusive – we are content with WG's approach.

Island connections

Q10 (MITS/Local nodes) – please see "Sharing and Local/Wider" para above.

Q11 (Security Factor) – please see "Sharing and Local/Wider" para above.

Q12 (Expansion Factor) – please see "island expansion factors" para above.

Q13 (Anticipatory MITS) – no comment.

Q14 (island connection) – please see "Sharing and Local/Wider" and "island expansion factors" paras above.

Q15 (overall view) – please see "Sharing and Local/Wider" and "island expansion factors" paras above.

Implementation

Q16 (Which option) & Q17 (transitional approach) – please allow time to fully develop proposals. Each of sharing, HVDC and islands could be treated as if they were separate modifications. See "Process Going Forward" para above.

Governance

Q18 (Alternative Request) – no.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	*Garth graham*
Company Name:	*Sse PLC*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We welcome the opportunity to comment on the CMP213 proposal via this Workgroup consultation. We have answered the 19 questions posed by the Workgroup in detail below and therefore having nothing further to add here at this time.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*. For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.* Firstly, we note the Proposer's view, outlined in the CMP213 Original proposal form submitted to the CUSC Panel on 29th June 2012 (and reproduced in Annex 2 of the consultation) about how this Original proposal does, in their view, better facilitate the Applicable CUSC Objectives for the Use of System Charging

	Methodology. Secondly, we note that CMP213 is still under development, both in terms of what will be the final composition of the Original and also what, if any, Alternative(s) might look like. Thirdly, we note that the Workgroup has itself still to consider if CMP213 Original (plus Alternative(s)) better facilitate the Applicable CUSC Objectives for the Use of System Charging Methodology. Therefore whilst, in principle, we agree with the views of the Proposer (back in June 2012, when raising CMP213 Original) that this proposal does better facilitate Applicable CUSC Objectives (a), (b) and (c) for the Use of System Charging Methodology this is just our initial view which may change, depending on what is determined (under the 'proposer ownership' principle) as being the Original after this consultation closes.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We have reviewed the various potential options for implementing CMP213 (along with the suggestion of a possible transitional arrangement) and have provided detailed comments in Q16 and Q17 below.

Specific questions for CMP213 – see attachment – proforma not allowing multi-page answers.

Annex to SSE plc Response to CMP213 Stage 02 Consultation

<u>Sharing</u> [pg 27-103]

Q1 [pg 58] Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?

We note the deliberations of the Workgroup, as set out in Section 4 and have a number of observations.

We can understand the attempt to examine the variable elements affecting constraint costs and the discussion of this in paragraphs 4.33 to 4.100. However, we cannot reconcile the decision in paragraph 4.101 to “not look for a complex solution based on price” but that the Workgroup attempted instead to come up with a proxy for a price solution, which is as complex or even more so. We recognise that the Original provides a balance between complexity and practicability whilst being better in terms of cost reflectivity. However, we believe that the other options considered here are overly complex and do not provide a robust proxy for a solution based on price.

For example, we disagree with the proposition as illustrated in Figures 17, 18, 19, 20, 21, that there is one linear relationship between the load factor and incremental constraint costs of low carbon plant and a different linear relationship for non low carbon plant. We do not think that this has been clearly demonstrated and seems at odds with examination of actual bids and associated constraint costs.

This error (in terms of the five figures mentions above) is compounded by assuming that nuclear power plants have incremental constraint costs of a similar level to other low carbon plant when, in fact, such plants have, across the fleet, the highest Bid prices in the BM (at negative £10,000 for each plant).

This error (in terms of the five figures mentions above) is compounded by assuming that nuclear power plants have low incremental constraint costs when, in fact, such plants have, across the fleet, the highest Bid prices in the BM (at negative £10,000 for each plant).

One argument that has been put forward is that the published Offer prices of low carbon plant (nuclear and non nuclear) are closer together than those for non low carbon plant (such as CCGTs and coal).

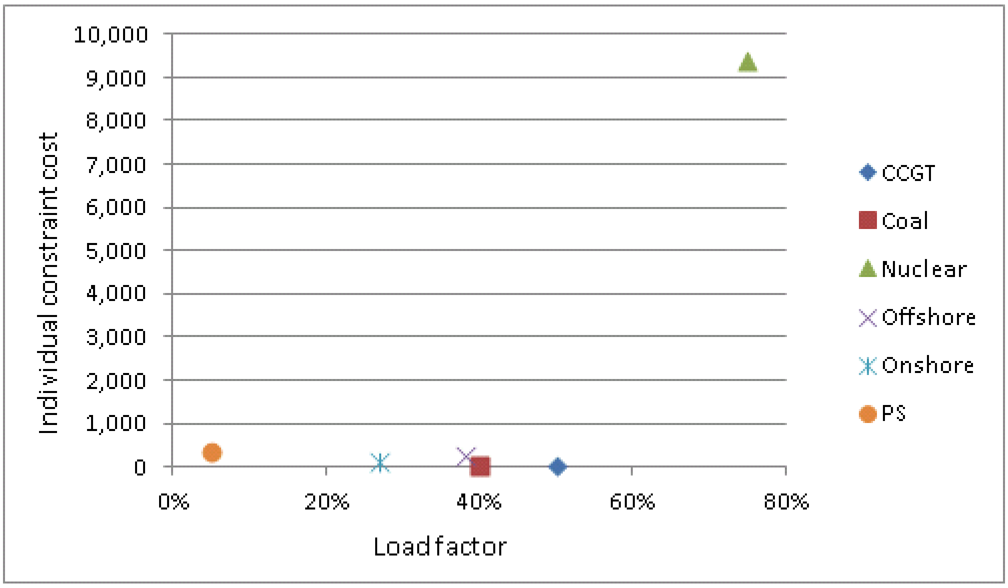
However, this is not born out by even a rudimentary examination of the facts. Taking nuclear generation Bid prices (at negative £10,000) as 100% and Bid prices of £0 as 0% then onshore wind generation, for example, has Bid prices in the region of negative £80-200 (or -0.8-2%) whilst non low carbon plant; such as coal and gas; have Bid prices in the region of positive £20-40 (or -0.2-0.4% in the reverse scale used in this simple example). Nuclear bid prices only vary to negative £9,900)

Thus it can be seen, via the published Bid prices, that renewable low carbon generation is far closer (in terms of incremental constraint costs) to non low carbon plant; being in a range of 1-2.4% (0.8 to 2% low carbon / -0.4 to -0.2% non low carbon) of the cost of nuclear low carbon (which varies by only 1% from the 100%).

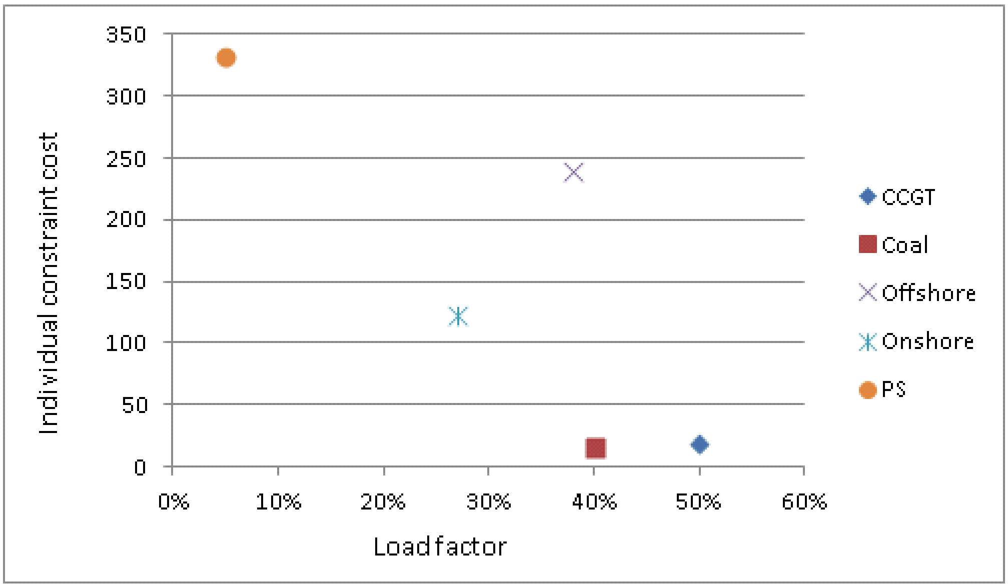
A further anomaly with this approach is that it appears that pump storage generation (where some Bid prices are higher than, for example, non nuclear low carbon generation) is included with non low carbon plant even though the range of offer prices is greater than the 1-2.4% range between non nuclear low carbon generation and non low carbon plant.

As a result we have serious reservations over some of the detail in the proposed ‘diversity’ approach set out in paragraphs 4.123-4.150 as it appears to distort the effect of the proposal by substantially altering the quantity of transmission capacity that is available to share between generators (especially in Scotland, and in particular the B6 Cheviot boundary).

We have reviewed bid prices for a range of plant, covering over 17 GW of plant, for one month from 24/11/12 to 24/12/12. (This period has been used as it is the most recent month available excluding the Christmas holiday period). In the following graph we show the calculated marginal constraint cost associated with these bids. This shows that there is not a strong relationship between plant load factor and bid cost according to the definition carbon and low carbon. The relationship is not clear as the bid cost of nuclear is so much lower than that for the other technology types.



Using a truncated scale for the constraint cost (y-axis) helps outline the relationship for the non-nuclear plant. Nuclear plant is excluded as its constraint cost is outwith the y-axis range. It is clear that the relationship between load factor and constraint cost does not split along carbon and low carbon lines.



In terms of the treatment of negative TNUoS zones, as set out in paragraphs 4.151-4.164, we concur that the Original proposal will be more cost reflective than the existing 'baseline' ICRP approach.

In this respect we agree, in particular, with the view that the existing 'baseline' ICRP approach "...is over rewarding these power stations in negative zones and more generally in the southern part of the GB transmission system". We note that as the amount of funds to be recovered from generation (across the whole of GB) remains the same that over rewarding of power stations in negative zones comes at a direct cost to those generators in positive zones. This is detrimental to competition in generation as it results in a subsidy being paid by generation in positive zones to those in negative zones. This does not better facilitate the applicable objectives – CMP213 by correcting this defect does, clearly, better facilitate the applicable objectives in terms of the charges applied to generators in negative zones.

We also would wish to raise the issue that CfD low carbon plant will not follow the same bid pricing as RO low carbon plant. In fact CFD plant may exhibit bid prices very similar to non low carbon plant. Hydro plant with storage, which does not have low energy spill cost, will also exhibit bid prices similar to non low carbon plant.

Q2 [pg 72] Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.

Taking into account the Workgroup deliberations, in paragraphs 4.165-4.247, we believe that all the practical options for calculating the sharing factor have been taken into consideration.

As has been indentified by the Proposer and the Workgroup in setting the ALF sharing factor a balance needs to be struck between three often contradictory elements:-

Simplicity / transparency;
Stability / predictability; and
Cost reflectivity.

We are persuaded that the benefits of the Original approach (five year ALF with the highest and lowest values discarded) as set out in paragraph 4.182 outweigh the dis-benefits set out in paragraph 4.183.

The TEC (MW) option is retention of the 'status quo' approach and does not therefore, in our view, better meet the applicable objectives on the ground of not being as cost reflective as either the original or some of the other options in table 15.

The main drawback of the NETS SQSS approach is that a wide range of generation technology categories is needed to allow the generic factors to align with actual load factors. This makes for complexity and uncertainty in terms of setting parameters administration as well as the potential of significant divergence between the generic load factor and the actual for most generators.

The generic approach also shares the drawbacks of complexity, uncertainty and the potential of significant divergence between the generic load factor and the actual for most generators.

We believe that this leaves the use of a forecast as the best practical option. In terms of a National Grid forecast we suspect this would, in practice, either be based on the ALF (or a variation of) or the NET SQSS approaches – so this would not be any better / worse than either of those approaches.

In respect of the User forecast, with a clear reconciliation approach to incentivise accuracy in that forecast we believe this may have merit as it addresses some of the perceived drawbacks with the ALF approach of the Original.

Taking all these factors into account whilst we support the Original proposal, we can see a distinct advantage (over and above the ALF) if the proposed Hybrid approach (of using either the ALF or a User Forecast) is adopted when determining the sharing factor. We therefore support this as our preferred option.

Q3 [pg 76] On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?

We note the deliberations of the Workgroup, set out in paragraphs 4.238-4.266. In our view the arguments set out in paragraphs 4.253 and 4.254 and the analyses presented in figures 33 and 34 point to intermittent generation not being exposed to a Peak Security element in their TNUoS tariff composition.

This is reinforced by the statement, in paragraph 4.26.2, that "...the deterministic standards against which transmission network capacity for demand security reasons is planned currently dictates that wind generation has no influence on the incremental need for transmission network capacity at times of peak electricity demand."

Q4 [pg 103] Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

Yes, we consider that all practical options have been considered, however we consider that some impractical options have also been considered. Thus if all options are to be retained for further consideration we think it appropriate that other options such as distinct plant by plant, stochastic based bid and output level pair based sharing are considered.

Q5 [pg 103] What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?

We believe that the general principle of load based sharing is incorporated into the methodology as there is a clear logic for this. We believe however that all attempts to make a clearer link to sharing potential for assets is likely to bear little in terms of improved cost-reflectivity whilst introducing a greater administration burden and the risk of discrimination based on non-representative models of the true impact of capacity sharing.

HVDC [pg 104-114]

Q6 [pg 111] Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.

Having reviewed the information set out in Section 5 it appears that all the relevant options and potential alternatives for how the expansion factor should be calculated have, so far, been considered.

However, we believe that the Workgroup has to fully recognise that the treatment of the only HVDC link under construction (which parallels the onshore AC network) within the charging methodology should reflect the fact that as the cost of both the onshore and offshore links are similar (or less) that the eventual charges should also be similar (or less) depending on the capacity of the onshore link.

In the absence of evidence from the TOs (or Ofgem) to the contrary we believe the capacity figure for both links are similar (at ~2.2GW) and therefore the effect on TNUoS tariffs should also be similar. It would, for example, be very odd for the two TOs concerned to have modelled a significantly greater onshore capacity for the onshore link (compared with offshore) as this would seem to undermine both their public statements (and those of Ofgem / DECC).

In coming to this view we have noted, in particular, the deliberations set out in paragraphs 5.46-5.54. Given that the published cost of the Western HVDC is in the order to £1,051M[1] and the capacity is in the order of 2.2GW[2] and that, according to the two respective TOs, the

[1] Ofgem 27th July 2012 http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents1/Jul12_WHVDC_decision_FINAL.pdf

[2] Ofgem 21st May 2012 http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents1/TII_May12_WHVDC_consultation.pdf

cost is similar[3] to the parallel (onshore) AC 400kV circuits (and according to the regulatory bodies the cost, of going offshore, is less[4] than onshore) we would expect the cost, in terms of TNUoS tariffs, to also be similar (or indeed, based on the regulatory analysis, less) between the offshore cable and the onshore route.

In other word, for illustration purposes only, **if** the effect of building the onshore capacity was £1 (in terms of TNUoS tariff increases for those Users north of the B6 boundary) then the effect of providing that capacity via the offshore Western HVDC should be similar at £1; i.e. it might, say, be £0.95p or £1.05p depending on what the actual costs (as shown in the TOs CBA provided to Ofgem) was.

This is what any neutral observer would expect – the cost of the link is similar, the capacity is similar therefore, if the TNUoS charges are to be cost reflective then they too should be similar.

However, we note that it has been difficult to source what, approximately, is the capacity of the onshore parallel AC circuits that have been modelled / assessed by the two TOs involved in this project (and by Ofgem / DECC).

Clearly with the cost being similar (according to the TOs - or less according to Ofgem / DECC) at £1,050M if, therefore, the onshore capacity modelled was twice that of the Western HVDC at, say, circa 4.4GW then, in terms of the *illustrative* example used here, the effect on TNUoS tariffs (for those Users north of the B6 boundary), should be twice that of the equivalent parallel onshore network; i.e. in the order of £2 for going offshore compared with £1 for the equivalent onshore.

However, if for example the effect on TNUoS tariffs (for those Users north of the B6 boundary) of going offshore was 10 or 20 times greater then this clearly implies that the parallel onshore AC circuit capacity that was modelled by the two TOs (and reviewed by Ofgem / DECC) would be 10 times; i.e. 22.2GW; or 20 times (44.4GW) greater. This is

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[3] Joint SPTL/NGET Planning Statement Western Link (July 2012) paragraph 2.5.2. "Analysis of the existing onshore system showed that the volume of additional capacity required could only be provided through the construction of new transmissions circuits and upgrading of certain existing circuits. Due to the number and scale of these works it was concluded, in this particular case, <u>that the cost of onshore reinforcement would be similar to that of an offshore HVDC</u>."

[4] Joint DECC / Ofgem ENSG report 'Our Electricity Transmission Network: A Vision For 2020' (February 2012) [page 70] "A number of alternative onshore solutions were considered to increase the boundary capability of the B6, B7 and B7a boundaries. These included:

A number of projects have already been planned to ensure that the maximum capability (4.4GW) of the existing circuits can be realised. Further reinforcement would be required in the form of either two new 400kV transmission circuits: one from the West of Scotland to Lancashire and one from the East of Scotland to North East England or reconductoring existing 400KV double circuit between Harker and Strathaven and additional series compensation in these circuits to provide the necessary boundary capacity. These options were discounted for three main reasons:

(a) They did not represent the most economic solution. The total length of the new circuits would be in excess of 600km; <u>this resulted in a total project cost that was higher than the undersea HVDC option</u>.

(b) The construction of new onshore overhead line routes would have a greater disruption to land and higher visual impact.

(c) The timescales required to progress a project through the planning and consents process as prescribed in Appendix F would result in higher constraint costs.

For these reasons it was decided not to progress with onshore AC reinforcements."

because as the cost remains similar (or less) the only other variable, in terms of cost reflectivity, is the capacity to be built.

Only in this way could it be said that the TNUoS tariffs for Users north of B6 are cost reflective, with respect to the effect of building (and charging for) the Western HVDC link.

Our understanding is that the capacity of the onshore route is neither 10 nor 20 times that of the offshore cable and therefore cannot reconcile why the offshore cable should be so much higher (in terms of TNUoS charge) than the onshore route. That being the case, we believe that this aspect needs reconsidered by the Workgroup.

Q7 [pg 113] Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?

The treatment of the HVDC in load flow modelling should be dependent on how the expansion factor of HVDC is treated in order to accurately reflect the underlying reasoning behind the HVDC investment decision. If HVDC is treated with an expansion factor equivalent or lower than the alternative AC investment then it is reasonable to use a methodology that maximises flow on the HVDC. If HVDC is treated with a higher expansion factor then a methodology that minimises flow on the HVDC should be used as the logical expansion decision for the TO would not be to expand the HVDC system given its greater expense compared to the onshore options.

Q8 [pg 114] Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

We consider that, given that HVDC investments are not being sanctioned to deal with flow at peak demand, it is appropriate to give consideration to a method that reflects this in how circuit faults are treated. We suggest that a methodology that uses a cost multiplier of 1/1.8 for the HVDC circuit MW-kms be examined. This would reflect the fact there is no redundant HVDC capacity whilst recognising that the model incorporates a standard 1.8 security factor for the MW-km associated with the HVDC circuit. We consider that this gives a more appropriate cost reflectivity.

Q9 [pg 114] What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?

We have considered the options set out by the Workgroup in Section 5, and have the following comments.

a) i) Remove all converter costs from the calculation

We agree with those Workgroup members that believe that all the cost of the HVDC convertor station should be removed from the locational charge and, instead, be placed in the residual charge element of TNUoS tariffs.

In coming to this view we agree with the views of Workgroup members noted, for example, in paragraphs 5.21-5.24.

We note the counter arguments including "....that in order to use HVDC cable technology converter stations are necessary, that these converter stations add to the cost of this transmission technology and as such should be included in the locational signal..." (paragraph 5.26) and observe the same could be said about transformer and substations as without them the onshore AC circuits could not function.
Or to put it another way, paragraph 5.26 could be read as:

> "....that in order to use *onshore circuits transformers and sub stations* are necessary, that these *transformers and sub stations* add to the cost of this transmission technology and as such should be included in the locational signal..."

Clearly it has been a widely justified and supported principle (a principle that we whole heartily agree with) that certain fixed elements of the transmission system should be recovered of all users of system (via the residual charge). In our view HVDC convertor stations exhibit the characteristics of similar fixed elements of the transmission system and should, accordingly, be charged in the same way; i.e via the residual not the locational element of TNUoS.

a) ii) Remove some converter costs from the calculation

i) Remove a percentage of the HVDC converter station costs based on elements similar to AC substations

Whilst not detracting from our position set out under (a) (i) we nevertheless recognise the deliberations of the Workgroup (paragraphs 5.30-5.35) in considering if there are certain cost elements associated with HVDC convertor stations that could be considered 'fixed' and others 'locational'.

In light of the analysis of the typical breakdown of HVDC convertor station costs shown in Table 18 then if the arguments set out under (a) (i) do not carry the day then the approach proposed by the Workgroup in paragraph 5.35 would seem the next most suitable approach.

ii) Remove a percentage of the HVDC converter station costs based on controllability similar to QBs

Noting the Workgroup deliberations set out in paragraphs 5.36-5.44 and for the reasons we have just set out under (a) (ii) (i) above we agree with the suggested approach in paragraph 5.44.

Having taken into account the deliberations set out in paragraphs 5.30-5.44 we agree with those members of the Workgroup (paragraph 5.45) that both a 10% (for the QBs aspects) and a 50% (for the cost element aspects) reduction are fully justified.

a) iii) Treat HVDC cost as onshore AC transmission technology cost when calculating the expansion factor

For the reasons we have detailed in our response to Q6 above, we believe there is a very strong case to argue that the expansion factor associated with an HVDC which parallel onshore AC network should be similar to that onshore network where the costs are similar (or less) and the capacity is similar.

If this was not to be the case and the TNUoS charges, as a result, were different then this would clearly be (a) discriminatory and (ii) not cost reflective (and thus would not better facilitate the applicable objectives).

Equally, where the costs are similar (or less) but, for example, the parallel onshore AC network capacity is, say, double that of the HVDC link then a properly functioning cost reflective charge for the onshore option would be half that of the offshore option. (But not a tenth or twentieth)

Put another way, if the offshore charges are not, in this case, broadly double those for onshore then they too are (a) discriminatory and (b) not cost reflective (and thus do not better facilitate the applicable objectives).

i) Review the overhead factor (i.e. 1.8%) used when annuitising the capital cost in the calculation of the expansion constant

We welcome the thoughtful deliberations of the Workgroup, as set out in paragraphs 5.55-5.63, with respect to how the overhead factor for HVDC links might be annuitised.

These deliberations, and the analysis from Parsons Brinkerhoff, are a helpful contribution to the debate on this particular matter and we concur with the view set out in paragraph 5.63 namely that the greater benefits of simplicity and stability associated with using a single overhead factor (of 1.8%) for all transmission assets (be they onshore AC circuits or offshore HVDC circuits) outweigh the minor detriment to cost reflectivity associated with not having a more specific treatment (for HVDC).

ii) Calculate the 'desired flow', and hence impedance, by balancing flows across the single most constrained transmission boundary rather than all the transmission boundaries the circuit crosses

Having considered the deliberations of the Workgroup, as set out in paragraphs 5.64-5.68, and being mindful of the points we have made in response to Q6-Q8 above, we are of the view that the Original proposal (of reflecting the multiple boundaries crossed by the HVDC link) is the most appropriate.

In our view the use of the single transmission boundary approach (paragraphs 5.66-5.67) would:-

1) be inaccurate (as, clearly, multiple transmission boundaries are being crossed);
2) not reflect what happens in reality (in terms of SO system operation, as the crossing of all the transmission boundaries would be factored in by the SO in its determination, on the day, of the use of the HVDC link); and
3) not be cost reflective (as it would attribute the cost arbitrarily to a single transmission boundary).

Therefore the single transmission boundary approach should not be adopted.

<u>Islands</u> [pg 115-131]

Q10 [pg124] Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?

We note the deliberations of the Workgroup, as set out in Section 6, and concur that all the options and potential alternatives for island nodes classed as part of the MITS and those classed as local have been considered. Therefore we have not identified any other options which we would like the Workgroup to consider.

Q11 [pg 127] Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?

Being mindful (1) of the Workgroup deliberations, as set our in paragraphs 6.71-6.81, and (2) the Project Transmit Technical Working Group deliberations we concur that the most appropriate global locational security factor, in the case of islands not exhibiting redundancy on their linkage with the MITs is 1.0 (compared with the 1.8 applied elsewhere).

In respect of the matter of generator compensation (paragraph 6.75) and in particular “that generation Users would not be eligible for CUSC compensation for loss of the single transmission circuit element” we agree with this with respect to where the loss has been on the single circuit (to which 1.0 is applied).

However, for the avoidance of doubt, we would not support a removal of compensation to the generator if they are being charged (as part of their overall TNUoS charge) for more than a single transmission circuit (i.e. 1.8) and that element (rather than the single transmission circuit) failed. In such a situation the generator is entitled to compensation (as they are paying for the redundancy).

Q12 [pg 130] Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.

With respect to how HVDC links to the islands should be charged whilst noting the deliberations of the Workgroup in paragraphs 6.82-6.99, we believe that the points we have detailed in response to Q6-9 should equally apply where HVDC technology is used to connect islands to the MITS.

Briefly, we can see a case for all the HVDC Convertor Station costs being treated as fixed (rather than locational) and thus recovered via the residual.

Whilst some have suggested this principle might also be applicable to offshore transmission connections we note firstly that islands are intrinsically part of the ‘onshore’ transmission system as they have always been covered by the licensed areas of the three transmission companies (since privatisation) unlike offshore and secondly, they have actual customer demand (as opposed to 'station demand') associated with them.

Notwithstanding that, the approach whereby a proportion of the costs of the HVDC convertor station costs; i.e. the 10% for QBs (if applicable in terms of VSC v CSC convertor technology adopted on the link(s)) and 50% for similarities to AC; should be adopted if the full convertor station costs are not to be recovered via the residual.

Q13 [pg 131] Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.

The deliberations of the Workgroup in paragraphs 6.100-6.113, with respect to anticipatory investment and the associated 'achievement' of MITS status on an island prior to it actually occurring, highlight a number of benefits and consequences from adopting some form of anticipatory approach to charging for forthcoming transmission investment required as a result of (anticipated) generation investment.

These arguments, with respect to the benefits and drawbacks identified by the Workgroup, are finely balanced and, at this time, we are not persuaded that the benefits outweigh the drawbacks.

In addition we believe there may be some further, practical aspects to be considered, for example: how far in advance should the SO look (what is the timeframe for their 'window'); what if a generator 'gamed' the situation by creating a real project and a 'cardboard' project the connection date for which was constantly being pushed back (but still falling within the timeframe window that the SO would be taking into account)?

Therefore, taking it all into account, we currently believe that, whilst the Workgroup has considered the relevant options and alternatives, the application of an anticipatory approach, with respect to islands (or wider afield), should not be taken forward.

Q14 [pg 131] Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

We note the various options identified by the Workgroup in, for example, the table after paragraph 6.12, table 19 and table 20 and the associated detail for these in Section 6. We believe that the Workgroup has adequately considered all the relevant options and potential alternatives for island connections at this time.

Q15 [pg 131] What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?

As we have set out in our response to Q11 and Q12 above, there are a number of items that we believe should be taken into account when determining the best way of including island connections comprising sub-sea cabling and / or HVDC technology into the TNUoS charging methodology.

Firstly, we consider that it is appropriate that the global security factor for islands not having redundancy on their linkage to the MITS is 1.0 and that in this case generation Users would not be eligible for CUSC compensation for loss of service caused by a failure of the single circuit.

Secondly, if a lowered global security factor is not applied to islands not having redundancy on their linkage to the MITS, generation Users must be entitled to CUSC compensation for loss of service equivalent to mainland MITS generation Users.

Thirdly, we consider that HVDC Convertor station costs should be treated as fixed as opposed to locational costs, equivalent to how transformers and substations are treated in the baseline ICRP, and included in the residual.

Finally, we consider that an appropriate proportion of the HVDC convertor costs are excluded from the locational cost if the full convertor station costs are not to be recovered from the residual.

Q16 [pg 137] The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.

We have considered the four implementation options set out in Section 8 of the report.

It is important in considering implementation options that implementation of the charging methodology modifications should not be further delayed. Given that industry has been working on this since September 2010 the Workgroup timetable should not be allowed to slip further in order to analyse more options. Any additional analysis should be undertaken in parallel but within the current timescale.

In our view Option 1 (mid year 2013-14) is the preferred option with, as a fallback, Option 2 (1st April 2014).

In coming to this view we are mindful of the Authority Direction issued to National Grid and in particular the comments in the covering letter[5], of 25th May 2012, that:-

"Industry will decide the manner and timing of the industry process, but we continue to urge industry to expedite this process and submit a final CUSC modification proposal report, with all the requisite justification and evidence, in a timely manner to ensure benefits are realised as quickly as possible."

We note that industry has been aware of the possibility of a substantial change to the basis on which TNUoS tariffs are calculated since at least September 2010.

For example, the initial Project Transmit SCR Call for Evidence was published[6] on 22nd September 2010 and concluded, with a direction to National Grid, on 25th May 2012.

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5 http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20SCR%20cover%20letter%2025%20May.pdf

We further note that Ofgem has been seeking the expeditious implementation of a long term solution to TNUoS charging associated with its Project Transmit since its inception with, for example, a number of Ofgem statements referring to a possible implementation date of 1st April 2012:-

i) Ofgem 'Project Transmit: approach to electricity transmission charging work' letter 27th May 2011[7]

"If appropriate, we aim to implement any change to TNUoS in time for the next charging year, i.e. from April 2012."

ii) Ofgem Project Transmit Stakeholder event 11th August 2011 'Opening Presentation' (slide 4)[8]

"*New Charges Target Date Apr 12*"

iii) Ofgem Project Transmit Stakeholder event 11th August 2011 'Closing Presentation' (slide 2)[9]

'Implementation'

•*Initiate CUSC process and NGET 2012/13 tariff development –December 2011*

•*Aiming for change, if appropriate, by April 2012–feasibility to be discussed at WG and through consultation process*

•*Ultimately, industry will decide the manner and timing of implementation*

iv) Ofgem 'Project Transmit: electricity transmission charging Significant Code Review update' 9th September 2011[10]

"...*Implementation of any change, if appropriate, would therefore be after April 2012, the potential implementation date we identified previously*."

Thus, in our view, Users (and especially those with generation assets, who will be directly affected by the CMP213 associated changes to TNUoS) have had sufficient time to factor the possibility of a substantial change to the methodology for calculating TNUoS tariffs (for generation) into their normal day-to-day risks.

Given (i) that the Authority seeks the expeditious implementation of a long term solution to TNUoS charging associated with its Project Transmit and (ii) that Users will have had (with a mid 2013-14, Option 1, implementation) circa three years notice of the broad intent along with circa 18 months notice of the broad tariffs that Option 1 is the most appropriate implementation approach.

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[6] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/PT[7] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf

[7] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf

[8] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Ofgem%20opening%20presentation.pdf

[9] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Ofgem%20closing%20presentation.pdf

[10] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=151&refer=Networks/Trans/PT

In regard to the other implementation options, as noted above, we consider that Option 2 has merit (as a fallback to Option 1) in that it exhibits the broad attributes of Option 1 (expeditious implementation) whilst allowing for implementation on the 'traditional' 1st April charging change date.

<u>We believe that any claimed impact on electricity supply tariffs is overplayed. Given that demand TNUoS charging is unchanged, and is now excluded from the SCR process, the only direct link between CMP213 and supply tariffs would be through the impact of CMP213 on wholesale prices. There has been no clear evidence produced to suggest that wholesale prices would increase under implementation of any of the options. In addition, wholesale price risk is a normal risk catered for by market participants.</u>

Q17 [pg 138] The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.

We note the deliberations of the Workgroup, as set out in paragraphs 8.26-8.31, with respect to transitional arrangements. Given that parties have had significant advance warning of the risk of this change (as detailed above in our response Q16) we do not believe that a transitional approach is required with respect to the implementation of CMP213.

In particular we find the suggestion that such a transitional approach, with respect to demand users, is (1) required and (2) needs to be over many years to be unsubstantiated, particularly as demand TNUoS charging is unchanged and is excluded from the SCR process.

If this were to be accepted then, on the grounds on non-discrimination, it would have to be applied to <u>all</u> changes to the TNUoS charging methodology in the future as well as any changes to the actual tariffs. (Some generation plant is likely to see a change to their tariff in excess of 20% across the period from 2012/13 to 2013/14)

It would also seem to be directly at odds with the Authority decision with respect to the 'mid-year' TNUoS tariff changes introduced on 1st December 2010 where timely implementation (outwith the 'traditional' 1st April date) was applied in order to better meet the applicable objectives, rather than delaying till the following spring.

With respect to generation TNUoS charges, Suppliers have been unable to show (a) that they have a significant proportion of their demand customers under long term contract (b) that those contracts are 'fixed' when it comes to the TNUoS methodology charges (e.g. they are not a 'pass through' element which alters as per the published TNUoS tariffs) and (c) that those contracts are directly linked to a specific generator, as opposed to being costed on the basis of the wholesale market price.

In respect of (c) we note that the proposed changes to the TNUoS charging methodology proposed by CMP213 will have no impact on the overall amount of money to be recovered from GB generators. Therefore whilst generators in certain parts of GB may, in the eyes of some, be considered to have 'lost' (if CMP213 is implemented) and others to have 'won' the overall effect on the GB wholesale price should be limited and may actually be positive.

Therefore there should be minimal negative, if any, impact on Suppliers and consumers, as Suppliers have costed their contracts with those customers based on the wholesale price.

Given that CMP213 original is, in our view, more cost reflective than the baseline (i.e. ICRP) we believe that any cost increase (in terms of impact on Suppliers) is firstly not proven, secondly even if it did exist is minimal (in the extreme) and, as a result, is far outweighed by the significant benefit associated with improved cost reflectivity and thus better facilitating competition in generation that arise from implementing CMP213.

Q18 Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?

We do not wish to raise a Workgroup Consultation Alternative Request.

Q19 Do you have any other comments?

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	Nick Oppenheim and Nick Kay on behalf of Uisenis Power Limited
Company Name:	Uisenis Power Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We are satisfied that the consultation is a comprehensive and well thought through process. At this stage however it is difficult to understand how the various options and alternatives will feed through to the resulting transmission charges. It would be helpful to see preliminary tariff assessments for the key options and alternatives taken forward as soon as this is available.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	In terms of facilitating effective competition the Original proposal is an improvement in recognising the different costs imposed on the transmission system by different types of generator and charging them accordingly, allowing fairer competition between generators of different types. However this should be applied to all parts of the transmission system, whether classed as wider or local, and should therefore apply to islands. Also, where demonstrated to occur, sharing should be applied to generators of the same type. There are aspects of the Original that would not help facilitate effective competition. For example the use of new technology, such as HVDC, can offer significant technical and environmental benefits over traditional AC solutions, and yet the methodology proposed in the Original could see generator TNUoS levels higher than had inferior, and more costly, AC solutions been implemented. The use of HVDC technology in the transmission network should not be hindered by a charging methodology that simply passes 100% of the costs to the connecting generators. The island links will be implemented as extensions to the onshore transmission network and as such any methodology adopted must seek to make island charges consistent with those

	of the mainland to ensure that island generators can compete on an equal footing with mainland renewable generation. This is essential to facilitate effective competition between generators otherwise there is a risk that a number of GWs of high quality renewable generation may not be connected. Our thoughts are explained further in the responses below.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	It would seem appropriate to work towards implementation of the modification for 1 April 2014. It is also noted that there could be a case for Ofgem to authorise National Grid to undertake preparatory work on generation TNUoS tariffs prior to Ofgem's final decision, this would be helpful.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	1.1 Whereas the Original proposal, accounting for sharing based on load factor, addressed sharing in areas dominated by certain generation types, the alternatives based on diversity between low carbon and carbon generation do not. Our thoughts are outlined further in Q2 below.

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	2.1 We understand that the Original proposal, accounting for sharing based on load factor, would see benefit for generation users in Northern Scotland through reduced TNUoS (Northern Scotland would reduce by around £10/kW from the current £22/kW). 2.2 It is noted that the introduction of 'Diversity' would serve to dilute the reduction for Scotland arising from the Original, by introducing the concept that sharing only occurs between carbon and non-carbon generation. It would be very helpful to understand how this would impact wider TNUoS in northern Scotland, although it would appear that the northern Scottish zones, where levels of carbon generation are low, would be most impacted by this. 2.3 We also note that the work undertaken by Heriot-Watt University on island sharing proves that sharing does in fact occur between low carbon generators. We are therefore of the view that the alternatives put forward on Diversity would not accurately reflect the level of sharing on the network, and sharing between low carbon generators would need to be incorporated into any Diversity methodology. We would also be concerned at the level of complexity, and therefore transparency, that the proposed alternative on Diversity would bring to the application of the TNUoS tariff. 2.4 The Heriot-Watt work demonstrates that sharing does occur between low carbon technologies on the islands. However it assumes that all island wind turbines will operate as a single generator, peaking at the same time. This would not happen in reality, where different wind farms, as close as a few km apart, would not necessarily peak at the same time. Indeed individual turbines within the same wind farm can perform quite differently, especially in complex terrains and in high wind conditions, as can be experienced on the Scottish islands. We therefore believe that the Heriot-Watt findings are conservative when it comes to the level of sharing between renewable generators.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	3.1 We believe this has been covered by the Workgroup.

Q	Question	Response
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	4.1 The work on sharing between low carbon generators, as demonstrated by Heriot-Watt, needs to be developed further and possibly incorporated into the alternatives developed for Diversity, as outlined in Q2 above.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	5.1 Where sharing occurs, whether between generators of different technology or between generators of the same technology, then it should be reflected in the TNUoS tariff. This applies equally to wider and local elements, and therefore islands. However, the charging methodology does have to balance complexity with a level of transparency to make any methodology workable, and it could be that cost reflectivity is best served by using a simple, but generator specific, load factor – as in annual load factor (ALF).

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	6.1 We recognise that a generic HVDC expansion factor determined from an average of HVDC project costs would be difficult to determine due to the limited number, and bespoke nature, of each HVDC circuit/connection. 6.2 We note that generic factors used for the AC transmission network allow for averaging of costs and would be likely to result in lower TNUoS levels for generators had AC solutions been adopted for the island connections. 6.3 We understand that the 2010 assessment for the Western Isles Link compared HVAC and HVDC solutions. The AC solutions were significantly more expensive, and yet the use of generic expansion factors and exclusion of the costs of fixed assets would result in a lower TNUoS for the generator. In addition generic expansion factors based on average costs avoid potential increases in locational TNUoS if specific costs should rise. 6.4 We would accept that a specific island expansion factor, to be determined on an island by island basis, could be appropriate for the new HVDC links. However this expansion factor should exclude the appropriate fixed cost elements. Removing cost elements will also lessen the potential for sudden price increases and help competition with mainland generators benefitting from generically determined TNUoS. 6.5 The use of AC generic expansion factors is also a feasible alternative where HVDC circuits are shown to have equivalent, or indeed lower, overall capital costs compared to equivalent AC solutions. 6.6 Generic factors would also help avoid sudden TNUoS price increases. For example, on the Western Isles the capital costs of the link have recently increased, and under the Original these cost increases would be passed through in full to the generators already committed to the connection and with user commitment in place. A significant factor in the cost increase has been the ground conditions of the underground cable section. Had an AC solution been implemented the generator would have been protected from these increases through the generic AC cable expansion factor.

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	7.1 We believe all options have been satisfactorily covered by the Workgroup.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	8.1 Picked up in responses to other HVDC questions.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	9.1 In line with island links we believe that it would be wrong to simply place all costs for the parallel circuits in the expansion factor. It is important to recognise, that whilst HVDC technology is relatively new, it has significant benefits compared to traditional AC technology. 9.2 We believe that the basic functionality of HVDC converters is the same as AC substations in that they transform electrical power into a form suitable for long distance transmission, and at the receiving end step is back in to a form suitable for distribution. As evidenced in the consultation report, costs could be less than AC solutions, and environmental impact will be significantly less. We believe that for the parallel links it would be reasonable, as a minimum, to exclude from the expansion factor the costs of the equivalent AC components, including substation and compensation equipment.

Q	Question	Response
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	10.1 We note that under the current definitions the Western Isles will become part of the wider network following the installation of the Western Isles Link (two transmission circuits supplying a GSP). However, we would see that island nodes could be classed as local, although we would see that this would only be on the basis that: • The Original proposal is then be adopted for wider sharing based on load factor • Local sharing is applied to each island circuit effectively enhancing the circuit rating for charging purposes. Local sharing should be forward looking and codified and could be determined and from the mix of generators with user commitment in place for each island link. The Heriot-Watt methodology, updated to include sharing between renewable generators (as detailed in paragraph 2.4), could be used as the basis to determine the level of sharing.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	11.1 We note that a security factor of 1 is proposed for island connections, and would agree that this would be appropriate for single circuit island links whether classed as wider or local.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	12.1 We note the options to deal with the costs of the converter stations, from all costs included in the expansion factor, to all costs excluded from the expansion factor, or a share between the two. As such we believe that the Workgroup has sufficiently considered the options. 12.2 However, under current methodology AC substations are excluded from the expansion factor, as are other fixed AC assets such as static compensation equipment and quadrature boosters. We believe that the basic functionality of HVDC converters is the same as AC substations in that they transform electrical power into a form suitable for long distance transmission, and at the receiving end step is back in to a form suitable for distribution. 12.3 We concur with the logic to exclude the AC elements of HVDC converters from the expansion factor. However, the DC element of the converters is able to offer significant benefits over passive AC systems, in that it is controllable, and can provide wider benefits to the networks to which converters are embedded. This is particularly relevant for HVDC converters based on Voltage Source (VSC) technology, our thoughts are outlined in more detail in the Island section. 12.4 To treat HVDC converters differently to AC substations because they are more expensive is too simplistic, and consideration should be given to the overall costs of all sections of the HVDC link (converters, subsea cable sections and underground cable sections) compared to an equivalent AC solution, as detailed in our response to Q14. AC cables for example are more expensive than HVDC, yet generic AC cable expansion factors are used to determine AC TNUoS levels that could be lower than HVDC. 12.5 We believe that it would be appropriate to remove all of the HVDC converter costs from the locational element, recognising the benefits of the new technology and also leading to TNUoS levels comparable with equivalent AC solutions with similar capital costs.

Q	Question	Response
12	Cont/	12.6 We note there are contrasting views in the report over the HVDC precedents established by offshore wind connections. We would argue strongly that HVDC, especially for island connections, should be dealt with independently from offshore connections. Whilst there are some similarities, there are also important commercial and technical differences between the two types of generation: • A specific regulatory framework has been established for offshore wind to facilitate the development of offshore wind technology, including higher levels of policy support and the OFTO arrangements in respect of the connection arrangements. • Island generators see the same levels of policy support to mainland onshore generators, and the island links will be implemented as extensions to the onshore TO's Transmission Licence area, they are not part of an OFTO's Transmission Licence. • Offshore connections tend to be specific links to individual generator stations whereas the island links will connect multiple generator stations covering different technologies. The island links will also serve to benefit the islands themselves improving the quality and security of supplies in these remote areas, providing capacity to facilitate island demand growth, and relieving reliance on local carbon standby generation. The new link to the Western Isles will relieve the heavily congested circuit to Skye, with demand being transferred to the new link.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	13.1 We consider all options have been covered.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	14.1 In terms of what has been considered, we believe that it would be wrong to simply place all costs for the island links in the expansion factor. It is important to recognise, that whilst HVDC technology is new, it can perform better than traditional AC technology, it has been demonstrated to be cheaper, and will have less of an environmental impact. 14.2 VSC based converter technology proposed for the island links is very controllable and in the correct circumstances installation of HVDC VSCs links can be beneficial to overall transmission system performance. 14.3 We understand that the Western Isles Link converter at Beauly will be used to support system voltage and will improve system stability in an important part of the network, the island converter will improve quality and security of supplies for the island. The black start capability of VSC converters will benefit the island following outages, restoring supplies without the need to start up standby diesel generation. 14.4 We understand, from the TNEI and PB Power reports published in 2010, that the costs of the preferred 450MW HVDC solution for the Western isles Link were lower than the AC solutions of the same rating considered at the time. 14.5 There are also important environmental benefits from the use of HVDC technology, cables are smaller and fewer are required, they are therefore easier to install underground, or sub-sea. Cables can be used over longer distances than AC, avoiding the need to use overhead lines. VSC converter stations have relatively small footprints, and the majority of equipment can be housed indoors. 14.6 For the proposed Western Isles Link, we understand that SHETL assessed all options taking into account technical, economic and environmental factors and concluded that a VSC based HVDC solution offers the optimum solution.

Q	Question	Response
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	15.1 Any solution for the island links should not be compromised by comparisons with elements of the offshore charging methodology, which has a completely separate and independent regulatory framework. 15.2 The island links will be implemented as extensions to the onshore transmission network and as such any methodology adopted must seek to make island charges consistent with those of the mainland to ensure that island generators can compete on an equal footing with mainland renewable generation. 15.3 HVDC is a relatively new technology which can offer significant technical and environmental benefits over traditional AC solutions, and yet the methodology proposed in the Original could see generator TNUoS levels higher than had inferior, and more costly, AC solutions been implemented. The use of HVDC technology in the transmission network should not be hindered by a charging methodology that simply passes 100% of the costs to the connecting generators. 15.4 Where sharing occurs, whether between generators of different technology or between generators of the same technology, then it should be reflected in the TNUoS tariff. This applies equally to wider and local elements, and therefore islands. Local sharing should be forward looking and codified, and applied to each island circuit effectively enhancing the circuit rating for charging purposes. Appropriate sharing could be determined from the mix of generators with user commitment in place for each island link.

Q	Question	Response
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	16.1 It would seem appropriate to work towards implementation of the modification for 1 April 2014. 16.2 It is also noted that there could be a case for Ofgem to authorise National Grid to undertake preparatory work on the generation TNUoS tariffs prior to Ofgem's final decision, this would be helpful.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	17.1 It would seem appropriate to work towards implementation of the modification for 1 April 2014, as above.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No.
Do you have any other comments?		No.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **15 January 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup report which is submitted to the CUSC Modifications Panel.

Respondent:	John Cunningham, Strategy Manager, Comhairle nan Eilean Siar, 07789 878840, jcunningham@cne-siar.gov.uk
Company Name:	**Comhairle nan Eilean Siar, Local Authority for the Western Isles of Scotland**
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The consultation is detailed and well developed but indicative tariffs for each of the options being considered would be useful.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	A purely cost reflective regime disadvantages the Scottish islands. The islands should not be penalised for pioneering HVDC technology through a direct 100% reflection of the cost of HVDC. Elements of the Radial Links should be removed from the charging calculation to better reflect parity with the mainland AC based charging methodology. These differences in approach do not facilitate effective competition.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	No Comment

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	Further consideration should be given to the extent of sharing on island circuits. The sharing argument seems to focus on 'dominant generation types' and insufficient consideration is given to diversity between low carbon technologies.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	More use should be made of the Heriot Watt analysis in Orkney which is applicable to all islands.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No comment.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Again, more use should be made of the Heriot Watt analysis on sharing. An island sharing factor should be developed which is anticipatory in order to better inform long run investment decisions by generators.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	TNUoS should be based on usage and not on installed capacity. Installed capacity as a basis for TNUoS calculation is outdated. Recognition should be made of the inevitable downtime of intermittent generators.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	A specific Island Expansion Factor for HVDC should be developed which excludes non-relevant cost items from the calculation, eg certain non-Transmission Converter Station costs. The mainland benefits from generic Expansion Factors which insulate TNUoS from fluctuations in the cost of specific projects. This is not the case for the islands, particularly in regard to recent cost increases in the Western Isles Link which could be passed on directly to TNUoS.

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	No comment.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	No comment.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	Non-transmission elements of Converter Station costs should be excluded from the TNUoS calculation
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	If any of the islands are to be treated as MITS, an effective sharing factor, across all technologies, must be introduced for consistency. Again, more use should be made of Heriot Watt's analysis and this sharing factor should be anticipatory in order to support advance investment.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Since there is no redundancy in the island links, a Security Factor greater than 1.0 can not be charged. The Comhairle would like to see a Security Factor of 1.0 whether links are classified as Local or MITS.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	In all other aspects, the Western Isles are an integral part of Scotland and the United Kingdom. However, when it comes to electricity networks, the Western Isles are treated as offshore generators with no local demand and no network sharing. Charging the absolute cost of HVDC links against TNUoS results in a forecast Western Isles TNUoS SEVEN TIMES the North of Scotland mainland, only 28 miles away across the water. This is a clear case of the islands being disadvantaged by national policy and represents a breach of European Directive 2009/28/EC. Island TNUoS should be pegged to the nearest mainland TNUoS, maybe no more than two times the corresponding mainland charge and the difference should be socialised. This is a small cost for OFGEM to pay for GW's of renewable energy, produced at a fraction of the subsidy cost of Offshore Wind. In the wider sense, island Renewable Energy provides unprecedented regenerative opportunities to the most fragile economies in the UK at little cost to the Government and removes the need for continued Government intervention by subsidy should the Renewable Energy industry not develop.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	MITS with a Security Factor of 1.0 should be applied anticipatorily to all island links. This will give needed certainty to prospective developers.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	The UK's electricity transmission system requires to be reversed in order to collect GW of electricity from Europe's area of best Renewable Energy resource around the Scottish Islands. The current TNUoS methodology simply consolidates an outmoded and unfit Fossil Fuel based network through a series of locational signals which effectively disadvantage the Scottish Islands. The benefits of HVDC technology to the wider network should also be taken into consideration in calculating island TNUoS.

Q	Question	Response
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	a) the islands should be treated for what they are – an integral part of the UK network which can provide GW's of power for consumption in UK (and European) urban centres at a fraction of the cost to consumer of Offshore Wind; b) HVDC technology is new and the islands should not be penalised for early adoption through absolute reflection of the full cost of this technology. Different pricing methodologies are being used for the mainland (generic AC Expansion Factors) and the islands (absolute 100% cost reflection of HVDC by project). This is clear disadvantage in European terms; c) sharing between low carbon technologies should be developed without delay and applied anticipatorily in order to support onshore wind but also marine technologies where Scotland has the potential to be a global leader; d) locational signals which disadvantage the islands (SEVEN TIMES higher than the nearest mainland) should be tempered by imposing a cap on island TNUoS relative to nearest mainland TNUoS with the difference socialised as an incentive to island generation.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	Production of indicative tariffs for the various options would be helpful.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	No comment.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No comment.

Do you have any other comments?	Indicative tariffs by option are essential for any effective assessment of Working Group outputs and should be developed as soon as possible. A generic Island Expansion Factors should be introduced to insulate committed island developers from ridiculous cost increases (the cost of the Western Isles Link rose by 70% in three months during 2012).

2. Code Administrator Consultation Responses

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Neil Davidson*
Company Name:	*Aquamarine Power*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	**We believe WACM number 7 is the best overall option. Justifications against the main constituent parts of the Original and the WACM's are as follows:** **Sharing – no diversity** Evidence base for ALF link to incremental constraint costs is strong, and a more consistent and long lasting relationship than other shorter term effects of bid price and diversity of plant in an area. Support no diversity overall as improves cost reflectivity without excessive complexity and links variability in charges with variability in useage, which is manageable by generators. **Sharing – diversity method 1** Impact of diversity on incremental costs has been demonstrated in principle, but concerned that all Diversity methods whilst attempting to improve the resolution of cost signals (i.e. average ALF to more specific targeting on zones) require some subjective assumptions for what is a complex and changing picture, so improvement in accuracy is debateable. Furthermore, the variability of charges being linked to diversity cannot be managed by generators as they have no control over where other generators locate. Of the three methods, Diversity method 1 employs LC/C assumptions but does not cap sharing at 50% (see Diversity 2 for comment on this), and it also avoids any

	on/off sharing signals for boundaries. On that basis, Diversity 1 is considered to be an improvement on the baseline but not an improvement on options with no diversity. **Sharing – diversity method 2** Methods 2 and 3 Diversity rather arbitrarily limit sharing at 50%, for which there is no empirical evidence. Therefore feel it is a step too far and requires more evidence. **Sharing – diversity method 3** As Diversity 2 **Form of sharing – ALF 5 year historic** Transparent, employs user data and practical **Form of sharing – hybrid** Less practical to implement than historic ALF but recognise why some generators would prefer it **Parallel HVDC and islands – Specific expansion factor (EF) targeting 100% of Converter costs** Targeting 100% of the costs locationally is inequitable with cost allocation in existing mainland expansion factors, and inconsistent with TNUoS principles which do not target fixed costs. **Parallel HVDC and islands – Specific EF, Generic 40% targeting of Converter costs for AC substation equivalence and Quad Booster-like benefits** Removing these costs achieves better parity with existing expansion factors and is more consistent with TNUoS methodology. **Parallel HVDC and islands – Specific EF, generic 50% targeting of converter costs for AC substation equivalence** Whilst this option does recognise equivalence on treatment of AC substations it does not attempt to target other fixed costs in the AC system.

	Parallel HVDC and islands – Specific EF, target according to removal of the exact cost of AC equivalent costs in each converter station As above, although recognise enhanced cost reflectivity of specific treatment, suspect cost breakdown will not be practicable to obtain.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	In terms of implementation date, we favour a 1 April 2014 implementation date, which, we note, is already delayed from the original Project TransmiT timetable. We would not wish implementation to be delayed for one or two players and would hope the impact could be managed on a case-by-case basis.
Do you have any other comments?	We acknowledge the work that National Grid has put into producing these results for the Code Administrator consultation. Whilst we feel that the results are sufficient to understand the broad direction of travel of impacts, we do feel that the results would be enhanced by some commentary for those parties interested in interpreting the results in the context of the modelling methodology. We welcome National Grid's commitment to do this via their own response to the Code Administrator consultation, and would welcome the opportunity for any clarifications arising via TCMF or some other informal forum, before Ofgem's own impact assessment.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Respondent:	*STEVEN C POTTINGER*
Company Name:	*BAILLIE WINDFARM LIMITED*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We believe WACM number 7 is the best overall option. Justifications against the main constituent parts of the Original and the WACM's are as follows: **Sharing – no diversity** Evidence base for ALF link to incremental constraint costs is strong, and a more consistent and long lasting relationship than other shorter term effects of bid price and diversity of plant in an area. Support no diversity overall as improves cost reflectivity without excessive complexity and links variability in charges with variability in useage, which is manageable by generators. **Sharing – diversity method 1** Impact of diversity on incremental costs has been demonstrated in principle, but concerned that all Diversity methods whilst attempting to improve the resolution of cost signals (i.e. average ALF to more specific targeting on zones) require some subjective assumptions for what is a complex and changing picture, so improvement in accuracy is debateable. Furthermore, the variability of charges being linked to diversity cannot be managed by generators as they have no control over where other generators locate. Of the three methods, Diversity method 1 employs LC/C assumptions but does not cap sharing at 50% (see Diversity 2 for comment on this), and it also avoids any on/off sharing signals for boundaries. On that basis, Diversity 1 is considered to be an improvement on the baseline but not an improvement on options with no diversity. **Sharing – diversity method 2** Methods 2 and 3 Diversity rather arbitrarily limit sharing at 50%, for which there is no empirical evidence. Therefore feel it is a step too far and requires more evidence. **Sharing – diversity method 3**

	As Diversity 2 **Form of sharing – ALF 5 year historic** Transparent, employs user data and practical **Form of sharing – hybrid** Less practical to implement than historic ALF but recognise why some generators would prefer it **Parallel HVDC and islands – Specific expansion factor (EF) targeting 100% of Converter costs** Targeting 100% of the costs locationally is inequitable with cost allocation in existing mainland expansion factors, and inconsistent with TNUoS principles which do not target fixed costs. **Parallel HVDC and islands – Specific EF, Generic 40% targeting of Converter costs for AC substation equivalence and Quad Booster-like benefits** Removing these costs achieves better parity with existing expansion factors and is more consistent with TNUoS methodology. **Parallel HVDC and islands – Specific EF, generic 50% targeting of converter costs for AC substation equivalence** Whilst this option does recognise equivalence on treatment of AC substations it does not attempt to target other fixed costs in the AC system. **Parallel HVDC and islands – Specific EF, target according to removal of the exact cost of AC equivalent costs in each converter station** As above, although recognise enhanced cost reflectivity of specific treatment, suspect cost breakdown will not be practicable to obtain.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	In terms of implementation date, we favour a 1 April 2014 implementation date, which, we note, is already delayed from the original Project TransmiT timetable. We would not wish implementation to be delayed for one or two players and would hope the impact could be managed on a case-by-case basis.
Do you have any other comments?	We acknowledge the work that National Grid has put into producing these results for the Code Administrator consultation. Whilst we feel that the results are sufficient to understand the broad direction of travel of impacts, we do feel that the results would be enhanced by some commentary for those parties interested in interpreting the results in the context of the modelling methodology. We welcome National Grid's commitment to do this via their own response to the Code Administrator consultation, and would welcome the opportunity for any clarifications arising via TCMF or some other informal forum, before Ofgem's own impact assessment.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	Prof. Furong Li; F.Li@bath.ac.uk Prof. David Tolley; DLTconsulting@btinernet.com
Company Name:	University of Bath Department of Electronic and Electrical Engineering
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; We do not believe the proposals of CMP213 would facilitate competition in the generation of electricity. Instead they will tend to result in the closure southern based marginal generation. This in turn will undermine the economic pricing of retail supplies. (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); The proposals will not result in charges that reflect the

	costs incurred by transmission licensees in their business. Instead they will spread these costs across the system leading to cross subsidy and inappropriate price signals. (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We do not support the proposed implementation. Instead we would wish to see alternative arrangements developed for implementing the objectives of CMP 213, which we do support. Our reasoning is described in the attached annex to this formal consultation response.
Do you have any other comments?	Further comments are described in the attached annex to this formal consultation response.

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Annexe to formal consultation response

We are pleased to note the significant efforts that the industry has made in seeking to reflect in the (TUoS) charging methodology the modification of the SQSS planning standards that incorporate a cost/benefit analysis (CBA) when determining the transfer capability of the main transmission boundaries. This recognises that the original investment cost related pricing (ICRP) only reflects network investment required to meet system security at times of peak demand, whereas improved ICRP (IICRP), and the variations to it that have been advanced, are intended to also reflect the CBA undertaken in planning developments to the system.

We welcome the purpose of this modification, but have serious concerns regarding the manner in which the use of a CBA has been reflected in IICRP. Our concerns relate both to the way that the CAB is implemented in IICRP and the potential consequences that will result for the security of the system.

At the heart of IICRP is the introduction of a second (year-round) background that is intended as a surrogate for the CBA in the SQSS, and where investment can only be justified if the cost of constraining generation is more expensive than the cost of reinforcing the system. This is achieved by projecting an optimised system at a time in the future where the incremental annualised investment cost equals the congestion cost. A key feature of this process is that constraint costs can then be determined from an approximation of the incremental investment cost. This implies that constraint cost will be proportional to the investment cost; for example the longer the circuit - the higher will be the constraint cost.

thus defer network investment that would otherwise be required

A major shortcoming with this approximation is that it reflects future system constraints rather than those seen today. At present the B6 boundary accounts for 80% of all system congestion but it represents only a relatively small proportion of the network assets. The key to improving ICRP should be to reflect the current level of congestion (bottlenecks) in the pricing model, together with their variation between boundaries and over time. NGET claims that it will invest in the system until investment cost equals congestion cost, i.e. the optimal system will be realised. If an appropriate economic signal is to be sent to network users so as to influence behaviour and reduce the current level of congestion then it needs to be based on the extant system and the current associated congestion.

The second notion introduced by IICRP relates to network sharing. The investment required at a boundary is deemed to be driven by either the peak security background or the year-round background that is intended to reflect the CBA. This simplification has a number of major flaws.

First it operates in the opposite direction to the revision to the SQSS. The modification to the planning standards was designed to recognise that investing purely for peak security could be expensive since system security could be compromised for only a short time. A CBA helps to determine how much investment is justifiable and how much investment can be avoided by incurring a limited cost of congestion. It is difficult to understand a logic that assumes that the investment cost should be derived from the larger of the two backgrounds.

Secondly network sharing is determined from the boundary power flows between two distinct systems; one that reflects peak security in the present system, and one that reflects a year-round CBA background in a future system in which generation output patterns have been significantly modified such that congestion and investment costs are matched. This cannot be cost reflective since it does not reflect the investment needs of the current system, or the congestion costs of the current system. Instead it links congestion costs with circuit length. The consequence of the approach is to spread the costs of investment needed to relieve the heavily congested boundaries across the whole system, thus significantly diluting the pricing signal for the investment required at relatively few but severe bottlenecks.

The third key idea in the IICRP proposals is the use of generation load factor as a proxy for the contribution a generator makes to system congestion. This assumption also has major shortcomings:

- It is not cost-reflective since the load factor assumption is linked to a future optimised system and does not reflect congestion cost in the extant system.

- Employing load factor to indicate a generator's contribution to system congestion and its cost also suggests that congestion is evenly spread throughout the year. In reality congestion at each transmission boundary is time limited, and the degree and duration differ markedly at each transmission boundary.

- If the network has infinite capacity, no matter what the generation/demand patterns are, there will be no network congestion. It is important to consider the impact of different generation technologies on congestion, but their effect is secondary.

- The key factor for network congestion is the transfer capability at each boundary. It is necessary to recognise therefore that there is a finite transmission capacity that is not evenly distributed. The level of congestion is therefore not uniform.

The critical factor of boundary transfer capability is not addressed in any manner in the proposals and the results from the IICRP proposals cannot therefore produce an outcome from the charging methodology that will create an appropriate economic signal for locating generation. Whilst the ICRP methodology in its current form does not reflect the CBA that is part of the SQSS, IICRP and its variations will tend to under-charge or under-compensate significantly marginal plant by spreading the congestion of a few bottlenecks to the rest of the system that has very little congestion, and from a limited congestion period to the whole year.

If the indicative tariffs provided for IICRP (and Alternative 1) were implemented then it would seem that some southern marginal (gas) plant would become uneconomic and thus face closure, even though these can support the system at times when the north/south flows become constrained. This would be an unfortunate outcome at a time when there are concerns over security of supply, and mechanisms are being contemplated to sustain generating capacity.

Further, it would expose future system security to the sufficiency of the existing network for transporting power from remote locations to centres of load. It would thus undermine the benefit the existing ICRP methodology provides for the more economic location of generation, and which is a further route to supporting system security.

Our view is that a debate is necessary on other alternatives that can be used to reflect congestion of the present system, rather than a future system, in the charging methodology. Under-charging and under-compensation created by the IICRP proposals may be worse than the original ICRP in meeting the charging objectives. Economic signals that can reflect the security needs and present congestion of the system will better influence users in the use of the current and future networks, and thus minimise the investment costs needed to accommodate the growth in low carbon generation.

If the IICRP approach or its variations were implemented congestion costs would rise as the signals sent do not reflect the nature and size of the investment needed for the system. This would result in even higher network investment and a reduction in network security whilst the investment was awaited.

Year-round System Congestion Costs - Key Drivers and Key Driving Conditions

A report to Centrica and RWE

Professor Furong Li
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January 2013

Executive Summary

Project scope and approach

Centrica and RWE have commissioned the University of Bath to undertake a review of two aspects of the proposals advanced in the CMP213 Working Group consultation of 7th December 2012. These relate to that part of the CMP213 proposals intended to improve the incremental cost signal in the ICRP methodology. Specifically, the University of Bath has been asked to address:

- The use of a generator annual load factor as a proxy for the causation of constraint costs; and
- The use of a dual background for devising the locational signal in TNUoS charges.

In order to address these points the University of Bath has undertaken a series of high-level studies based on a representation of the GB transmission system so as to test the basis for the CMP213 proposals. These studies focus on the key driving factors which determine year-round congestion costs. The studies attempt to answer three fundamental questions that underpin the network sharing concept.

i) Is it appropriate to assume that load factors can be used to represent a generation technology?

ii) Is it appropriate to assume a linear relationship between load factors and congestion costs, so that load factor can be used as a proxy for year-round congestion costs?

iii) Can a dual background realistically reflect the congestion conditions and thus its costs throughout the year?

Conclusions

The University of Bath supports the industry's effort to enhance the TNUoS charging methodology such that it can recognise the impact of differing generation technologies on incremental transmission network cost/congestion cost, particularly in the light of the rising volume of intermittent renewable generation across the system. However, we have serious misgivings over the direction that 'network sharing' takes in the original CMP213 proposals. We believe the approach proposed could seriously compromise the objectives of project TransmiT which are to "*to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers*".

i) Load factor analysis

Our work demonstrates that a generator's load factor is not a fixed parameter, but a highly complex parameter that is shaped by network location, network characteristics (in terms of length, capacity, utilisation, congestion across each interconnected boundaries), characteristics of generation (such as generation mix, efficiency, controllability, cost curves and output variability), characteristics of demand (such as demand duration curves, and demand profiles), the direction and utilisation of interconnectors, as well as market fundamentals. This is an important result because CMP213 uses a fixed load factor assumption to differentiate generation technologies as a key initial input to deriving charges. These are borrowed from the SQSS and then used to allocate circuits as falling into 'year-round' or 'peak' categories.

Our study shows that for the same generation technology but with different efficiencies (price), location, and boundary congestion levels, generators will have very different load factors. Our example shows that an increase in boundary capacity leads to less congestion resulting in lower cost generation being able to transfer more power thus increasing its load factor, whilst the load factor of the more expensive generation reduces. In the simplified network chosen for the study, when the transmission transfer capacity was increased by 25%, the load factor of the cheaper generator increased from 60% to 65%, while the more expensive generator load factor fell from 12% to 5%. The consultation document also observed that as the penetration of intermittent generation increases, the output of conventional generation will change and evolve with it over time.

Annual load factor for a generation technology is a variable that is shaped by differing generator and demand parameters, and features of the transmission system. It is thus inappropriate to use the same load factor for a generation technology regardless of its locations, efficiencies and market behaviour.

ii) The relationship between load factor and year-round congestion costs

When investigating the possible relationships between year-round congestion cost and annual load factor, we have illustrated how a change in wind penetration level, transmission capacity and generation price characteristics might impact load factor and congestion costs. Our studies demonstrated that under different network, generation and demand conditions the relationship between congestion costs and load factor can vary significantly. The relationship most certainly can not be assumed to be linear.

It is thus impossible to infer that by assuming linearity between load factor and constraint costs the charging methodology will be enhanced; unless account is also

taken of other factors such as location, efficiency, market conditions, and critically, the network transfer capability.

iii) The dual background approach

To examine the validity of introducing a dual background approach into charging as proposed by CMP213, we have developed the concept of a congestion duration curve that charts the variation in the magnitude of congestion costs throughout the year. The objective has been to investigate how congestion cost varies in strength and duration, over time and between locations.

Our study is of a system that comprises a representation of the B6 and B15 boundaries; the two GB boundaries with the heaviest congestions. The congestion duration curve in Figure 1 below shows that congestion arises in varying degrees, over different time periods. Table 1 shows that congestion cost is not only linked to the magnitude of congestion, but critically to time, duration and location.

Part 1 of the curve indicates a period of extremely high congestion where costs are in excess of £44k per settlement period. Although of considerable magnitude this high level of cost is incurred for only 23 settlement periods out of a total of 17,520 in the year. The proportion of the total annual congestion cost in this period is thus relatively small (1.1%), and can for all practical purposes be ignored when approximating the year-round congestion cost.

Part 3 of the curve represents the largest share of the year-round congestion costs but still only accounts for 5,427 settlement periods or 31% of the year. The issue in relation to the CMP213 proposals is that in the original proposals the annual load factor is averaged over the course of the year and consequently its use as a proxy for congestion could severely underestimate the congestion costs over the critical congestion periods; and thus significantly dilute the efficacy of the economic signals.

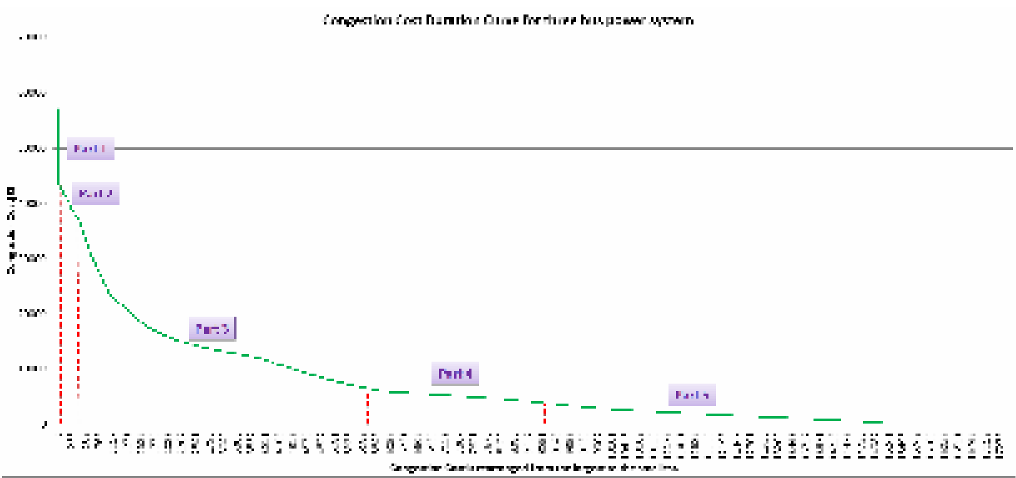


Figure 1: Congestion duration curve.

Table 1: Congestion cost between B6 and B15 for parts of congestion duration curve

	Number of settlement periods	B6 Congestion Cost £M	B15 Congestion Cost £M	Total Congestion Cost £M	Congestion share between different the 5 parts	Proportion of B6 in Total Congestion Cost	Proportion of B15 in Total Congestion Cost
Part 1	23	1.3	0	1,3	1.06%	100.00%	0.00%
Part 2	394	12.0	3.8	15.8	12.87%	75.75%	24.25%
Part 3	5427	67.4	11.3	78.7	63.91%	85.63%	14.37%
Part 4	3042	4.8	10.7	15.5	12.57%	31.44%	68.56%
Part 5	8634	10.9	0.9	11.8	9.58%	92.71%	7.29%
Total	17520	96.5	26.6	123.1	100.0%	78.38%	21.62%

We have also investigated the most significant periods that contribute to the majority of year-round congestion costs, and how the congestion cost is shared between B6 and B15 boundaries. Our study shows that the periods covering parts 2, 3, and 4 of the congestion duration curve shown in Figure 1 account for 94% of system congestion. It is these periods that should be adopted as background scenarios for deriving the year-round congestion costs sine they display both high magnitude and/or long duration.

The study also indicates that congestion costs not only vary over time and duration (different backgrounds), but also vary significantly between boundaries. The B6 boundary is responsible for over 80% of all system congestion, but this congestion does not occur with the same degree or at the same time across as across the B15 boundary. In fact the B6 and B15 boundaries are only congested simultaneously for 14% of the year. Furthermore congestion across B6, when it occurs is significantly higher than across B15. This suggests that congestion cost is sensitive not only to time and duration, but more significantly to the location of the boundary.

These differences of congestion in terms of magnitude, time and location are <u>not</u> reflected in the proposals for an improved ICRP. Employing load factor as a surrogate for the cause of congestion smears the consequence for one boundary across all boundaries and throughout the year. The use of annual load factors in a year-round scenario to reflect year-round congestion costs essentially assumes that all boundaries have the same level of congestion throughout the year. It cannot provide an appropriate economic message for reducing congestion, and it certainly will not reflect the costs of congestion in accordance with SLC 5.5b

Summary of Key Findings

- Annual load factor of a generation technology is not a fixed parameter but a variable that changes with generation, network and market conditions. It is thus inappropriate to use it as an input for a generation technology regardless of its location, efficiencies and market behaviour.
- The relationship between load factor and congestion cost most certainly can not be assumed to be linear. Load factor is a measure of an average output of a generation technology over the year; whilst congestion cost is sensitive to time (backgrounds), duration elements and boundary locations. The relationship between load factor and congestion cost varies greatly with transmission transfer capabilities, demand profiles and generation mixes, efficiency, controllability and their locations in the system.
- It is not appropriate to infer that by assuming linearity between load factor and constraint costs the charging methodology will be enhanced; unless it is further amended to take account of other factors, such as location, efficiency, market conditions and critically, network transfer capability.
- Even for a simple representation of the GB transmission system it is necessary to recognise at least five different congestion periods that will reflect the incidence of year round congestion. Within each period there are considerable differences in the timing and sharing of network congestion costs between the two most heavily congested boundaries.
- The single “year-round” condition is flawed in that it does not reflect the difference in magnitude, duration and location of the congestion. Instead the scenario proposed will represent an extremely high congestion condition that lasts for a very limited duration, and contributes little towards overall system congestion costs.
- Employing load factor as a surrogate for the cause of congestion smears the consequence for one boundary across all boundaries and throughout the year, by assuming that all boundaries have the same level of congestion at all times in the year. It cannot provide the necessary economic message for reducing congestion, and it certainly will not reflect the costs of congestion as required by the Licence Conditions.
- Our view is that a consequence of adopting the current CMP 213 proposals for an improved ICRP methodology will be to <u>increase</u> congestion costs, which would be perverse given the objectives of project TransmiT . Our conclusion is that employing only two backgrounds would fail to create even the crudest representation of system performance and costs.

Recommendations

- **Targeting TNUoS charges and credits in periods and locations where generator output contributes to, or relieves congestion would be an improvement to the existing**

ICRP methodology. However, this implies a time of use and congestion location feature in TNUoS charges rather than it being linked to generator annual load factors.

- **A TNUoS methodology that related charges to times and boundaries where congestion was most severe would be a significant improvement to the existing methodology. This could be achieved by introducing a time of use element (congestion factor) to the existing peak security based TNUoS charges. The present year-round scenario would be expanded to become a number of scenarios that are directly linked to congestion times and boundaries.**
- **If multiple scenarios with their respective time periods and duration are too complicated, then the existing ICRP methodology should be retained on grounds of simplicity rather than diluting and distorting its pricing incentives. Creating a dual background would be a retrograde step in the reflection of costs, and the provision of useful economic signals for transmission and generation investment.**

1. Introduction and Background

1.1. Study remit

Centrica and RWE have commissioned the University of Bath to undertake a critique of two aspects of the proposals advanced in the CMP213 Working Group consultation of 7th December 2012. These relate to that part of the CMP213 proposals intended to improve the incremental cost signal in the ICRP methodology. Specifically The University of Bath has been asked to address:

- The use of a generator annual load factor as a proxy for the causation of constraint costs; and
- The use of a dual background for devising the locational signal in TNUoS charges.

It has also been suggested that the conclusions should opine on whether a single background would better meet the required charging objectives, instead of the dual background proposed for the Improved ICRP proposals.

1.2. Charging principles

When assessing the merits of any future charging methodology it is useful to consider the relevant licence conditions. Standard Licence Condition SLC.5.2 requires that NGET "*make such modifications of the use of system charging methodology as may be requisite for the purpose of better achieving the relevant objectives*". The relevant objectives are described in SLC 5.5 and oblige NGET to ensure:

(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); and

(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses

NGET recovers its costs through TNUoS and BSUoS charges. TNUoS charges recover the revenues permitted under NGET's price control set by the Authority. TNUoS is currently based on the extant ICRP methodology that produces an economic signal for the location of generation and demand.

BSUoS recovers the costs of securing the system. It mainly comprises the costs of providing reserve in its various forms and the costs of resolving system constraints. The costs recovered by BSUoS have proved extremely volatile and difficult to predict, especially in the short term. BSUoS is levied equally on both generation and supply (in respect of demand) on an ex-post half-hourly basis. Socialising these costs between all parties is a political rather than an economic decision but it sits uneasily with the idea of incorporating constraint cost considerations into TNUoS charges.

1.3. Transmission congestion

The implementation of BETTA on 1st April 2005 increased sharply the costs of resolving constraints as is apparent from the following table:

Table 2: Change in constraint costs following BETTA implementation

£ million	2004/05	2005/06	2006/07
England & Wales	15.1	19.6	20.3
Cheviot (B6) boundary	0	31.6	20.3
Within Scotland	0	28.5	43.9
GB Total	15.1	79.7	93.2

During 2008 NGET provided Ofgem with its forecast of total system constraint costs in 2008/09 and 2009/10. This forecast suggested that costs would increase in these years to £238 million and £262 million respectively, of which around £210 million would be due to actions in the more northern parts of the GB system in each year.

Faced with this escalation Ofgem published (17th February 2009) an open letter expressing concern at NGET's substantially increasing forecast. The letter also noted the constraint costs that had been incurred since BETTA implementation. The data appears to be on a slightly different basis to that in the previous table but shows the same pattern in the two years post BETTA.

Table 3: Trends in constraint costs taken from Ofgem 17 February 2009 letter

£ million	2005/06	2006/07	2007/08
Arising from Scottish actions	70.0	80.0	42.0
Total GB constraint costs	84.0	108.0	70.0

The letter suggested a number of actions that NGET could take. These included:

i Actions to reduce the volume of constraints

ii Reductions in the price paid to resolve constraints iii Reviewing whether the charging mechanisms are "*equitable and appropriate*"

In view of increasing intermittent renewable generation, NGET raised a modification to the Security and Quality of Supply Standards (SQSS) that aimed to differentiate between conventional and intermittent generation when determining the system capacity needed to securely transfer power between zones. GSR009 proposed a "dual criteria" approach when planning reinforcement of the transmission network that would take account of both demand security and economic efficiency. The proposal was approved by Ofgem on 1st November 2011.

1.4. Significant Code Review

On 7th July 2011 the Authority announced that it would conduct a Significant Code Review under SLC 10 of the transmission licence with the objective of implementing the conclusions from its Project TransmiT. Project TransmiT was an open review of the transmission charging and connection arrangements in order to facilitate a smooth transition to a low carbon energy sector. The results of the SCR were published on the 4th May 2012. These noted (in paragraph 5.8) that:

> "*The use of a load flow model is robust if the incremental flows identified closely correlate with the resultant costs. The impact of this would be to promote more efficient decision making by parties… If, however, the relationship between costs and charges is more complex, then the retention of the existing ICRP methodology could have the effect of blunting the signals relating to the need for incremental requirements … and therefore the underlying costs of providing transmission capacity for different users at different locations*"

In the conclusions to the SCR Ofgem went on to direct (paragraph 5.9) that NGET:

> "*Develop an improved form of ICRP that recognises the dual background approach of the recently modified NETS SQSS*".

Ofgem's direction to NGET has introduced an unfortunate confusion that is repeated in the CMP213 proposals. GSR009 requires a "dual criteria" approach when assessing the transmission system capacity that should be provided. The first criterion, the ***demand security criterion***, requires the provision of sufficient capacity such that peak demands can be met without intermittent generation. This effectively carried forward the previous basis for the NETS SQSS. The second criterion, an ***economy criterion***, requires that sufficient transmission system capacity be provided to accommodate all types of generation in order to meet varying levels of demand efficiently. This part of the approach uses a generic Cost Benefit Analysis (CBA) to create an economically efficient balance between the costs of constraints, and the costs of transmission reinforcements.

The intention behind this "dual criteria" approach is clear. The deterministic peak load flow scenario would be overlaid by an economic assessment as to whether it would be more efficient to constrain intermittent generation off and other generation on, or provide additional transmission capacity in the event that the intermittent generation produced output at times of system peak. The Ofgem direction corrupts this starting point by requiring that NGET's modification should be based on a "dual background". CMP213 carries forward this confusion by promoting a peak and year round background as the basis for two separate charges, together with the allocation of circuits to one background or the other.

1.5. CMP213 objectives

Accordingly on 20th June 2012 NGET raised CMP213 with the objectives of:

- i Recognising the network capacity sharing by generators in the Investment Cost Related Pricing (ICRP) TNUoS charge calculation;
- ii Introducing an approach for including HVDC links that parallel the onshore AC network into the charging methodology;
- iii Introducing an approach for including Island links in the charging methodology.

This report addresses two of the issues relevant to the first of the stated objectives for the original CMP213 proposal, and which are raised in the CUSC Modification Working Group consultation of 7th December 2012. These are:

- i The use of generator load factor as a proxy for determining the costs of constraints on the transmission system; and
- ii The use of a dual as opposed to single background as the basis for deriving TNUoS charges for generation.

2 Load Factor as a proxy for determining constraint costs

2.1 Introducing the study

The CMP213 proposal adopts the approach that generator load factor can be used as a proxy for the incidence of constraint costs that would accompany an incremental MW at each node in a charging zone. The assumption is based on the empirical results from the use of the ELSI model which simulates the impact of various scenarios that could accompany future planning backgrounds for the system. The results from these studies have led to the conclusion that the relationship between congestion cost and generator load factor is linear. The methodology proposed for an improved ICRP (IIRCP) therefore asserts that generators with high load factors will contribute more to system congestion regardless of their location and time of generation; and thus should pay a greater proportion of use of system charges.

However, as the Consultation document notes, generator annual load factor is not a cost driver but merely the symptom of the relative economics of each generator "*including its availability, fuel cost, efficiency, CO_2 prices, and subsidies such as ROCs*" (consultation document paragraph 4.21). Furthermore the apparent empirical relationship becomes even less linear where there is a predominance of intermittent generation, which is precisely where theIICRP methodology needs to be most effective if it is to replace the current methodology.

Consequently our inclination is to share much of the disquiet that has been raised by many of the working group at this suggestion. The purpose of the study that is described below is to investigate whether the relationship between congestion cost and load factor is indeed linear.

2.2 The study framework

In this study three factors are chosen for the purpose of investigating their impact on the year-round congestion costs and generator load factor. These were chosen on the basis that they are the factors that are mostly likely to change in the near and medium term. These are the wind penetration level, transmission capacity, and the demand load factor, representing the factors that. The impact of each factor on congestion costs and generator load factor is examined by varying the values of the three factors.

The test system used for this study is illustrated in Figure 2. It is intended as a much simplified representation of the GB transmission system. Bus 1 and bus 2 represent two areas with different generation and load capacities. Area 1, which contains bus 1, has a high installed generation capacity but a low demand. Conversely area 2, which is linked to bus 2 has low generation and high demand. There are three generators in the system, two of which, generator 1 and 2, are thermal generators, and the third is a wind generator. Generators 1 and 3 are connected to bus 1, and are for most of the time behind a transmission constraint. Generator

2, which is the more expensive thermal generator, is connected to bus 2, it is required when there is insufficient generation at bus 1 to meet demand, or the transmission circuit is congested. The parameters for the generator capacities, transmission capacity and peak demand of the test system are given in Table 4. The output assumed for wind generation and demand are taken from actual historical data.

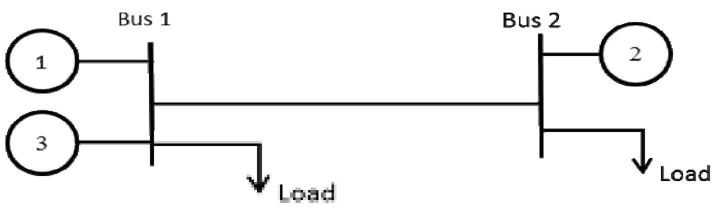


Figure 2: Two-bus test system

Table 4: Two-bus test system parameters

Bus 1					Transmission Capacity	Bus 2				
Thermal Generation		Wind Generation		Load		Thermal Generation		Wind Generation		Load
Price	Capacity	Price	Capacity			Price	Capacity	Price	Capacity	
Low	150	0.01	50	30	100	High	50	-	-	150

The principal assumptions for the model are:

- Thermal generation will be available whenever it is required subject to its rated capacity, which is given in MW in the table;
- Wind generation output is derived directly from the Met office wind speed data for 2011;
- Generator prices are such that generators connected at bus 1 will be despatched first to meet demand, with any resultant congestion being in the direction from bus 1 to bus 2;
- The branch between bus 1 and bus 2 represents the transmission network and is taken to have an appropriate impedance;
- A transmission constraint arises when the transmission capacity limits the power transfer from bus 1 to bus 2;
- Transmission losses and voltages are not considered in the study;
- The demand profile is taken form historical data for the GB power system in 2011;

- Demand profiles for loads at each bus are the same, which implies that the peak demand at bus 1 will be simultaneous with the peak at bus 2.

The simulation is made using Matpower with a DC optimal power flow. Generator offer and bid prices are set equal to their marginal generation cost

The constraint costs are simulated through two successive economic dispatches for each of the 17,520 settlement periods over the course of a year. The first economic dispatch is executed without consideration of the transmission capacity which represents the final physical position notified prior to gate closure. However, if the transmission capacity is exceeded then the generation is re-dispatched by reducing the output of the cheaper generation at bus 1, and increasing the output of the expensive generation at bus 2 until the overloading condition is resolved, i.e. Bid off generation at its marginal price in Bus1, and Offer On generation at Bus 2 at the SRMC. The congestion cost is defined as the cost of resolving the system constraints. Note that no premium is applied to bids and offers in this study, the constraint costs would be higher if these were included.

The model is then used to explore how wind penetration, transmission capacity, and demand load factor will impact the costs of resolving system congestion and be reflected in generator out-turn annual load factor.

2.3 Wind penetration impact on congestion cost & load factor

In order to examine the impact of the wind penetration level, the proportion of wind in the generation mix expressed on a per unit basis is varied between 0.05 to 0.71 times the wind capacity (50MW) of generator 3, whilst the installed capacities of the other generation technologies remains unchanged.

Figure 3 illustrates how the congestion cost changes as the wind penetration level increases from 2.5MW to 35.5MW. Initially the congestion cost increases as the transmission constraint is sustained over a longer period. Eventually the output from the wind generator cannot be transferred to the load centre, and at this point it is necessary to curtail the wind output and the constraint cost begins to decrease (in this study it is assumed that there is no cost to curtail wind, if a premium for Bids for the wind generation is used, then the constraint cost will rise when the curtailment of wind starts).

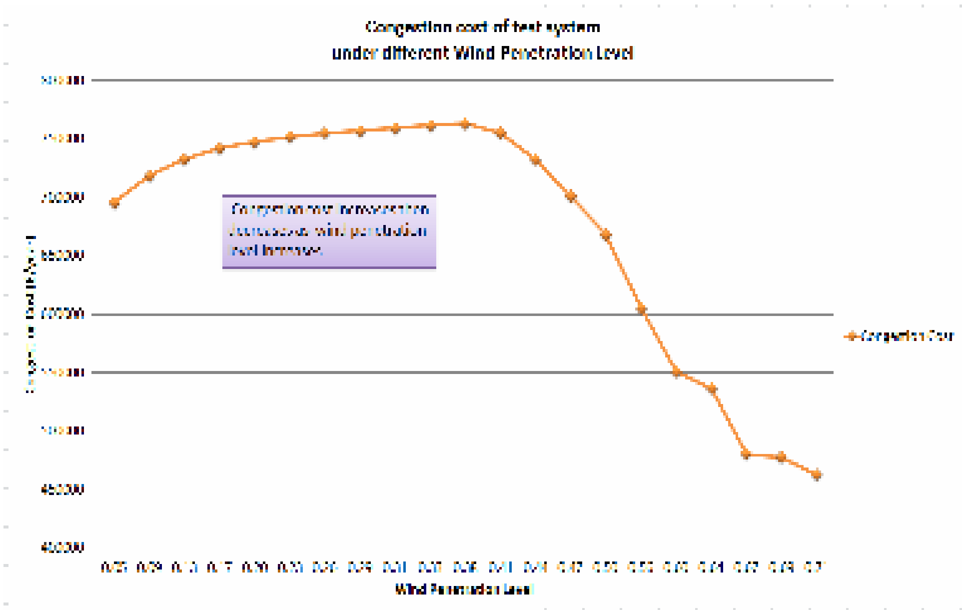


Figure 3: Congestion cost of test system under different wind penetration level.

Figure 4 then depicts the accompanying change in generator load factor with increasing wind generator penetration. The load factor of wind generation (green points in Figure 4) remains constant (at 0.33) until the total congestion cost hits the maximum value corresponding with the 0.38 wind penetration level. Before the maximum congestion is reached the cheaper thermal generation at bus 1 is dominant in determining the transmission capacity utilisation with wind generation replacing the cheaper thermal generation as the wind penetration level increases. The price difference between wind generation and expensive thermal generation drives a higher congestion cost. After the critical peak congestion point the load factor of wind generation starts to decrease, and the wind generation becomes a dominant factor in congestion alongside the cheaper thermal generator.

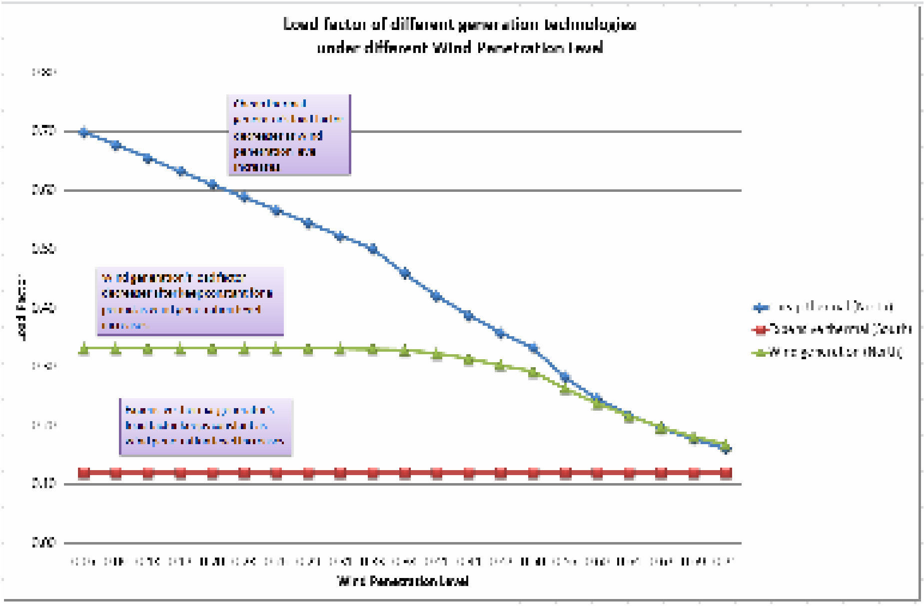


Figure 4: Generator load factors at varying levels of wind penetration

The load factor of the cheaper thermal generation (blue points in Figure 4) also decreases with the increase in wind penetration. As the transmission capacity must be shared between wind and cheap thermal generation it is inevitable that an increase in wind generation capacity will lead to a reduction in the output of the cheaper thermal generation.

The load factor of the expensive thermal generator (red points in Figure 4) remains constant since when demand exceeds the transmission capacity the excess of the demand above the transmission capacity must be met by the more expensive thermal generation.

Figure 5 combines figures 3 and 4 and shows the relationship between the congestion cost and load factor as the wind penetration level increases, which is depicted as a series of points which follow the direct of the arrow. As the wind penetration level increases, the relationship between congestion costs and load factor varies significantly for different generation technologies; the direction of change is shown by the three lines following the direction of arrow.

Before the wind penetration reaches 0.38, the congestion cost rises with decreasing load factors for both of the two generators (wind and low cost thermal) that are behind the constraint. Beyond a 0.38 penetration when wind curtailment starts to be exercised, the congestion cost decreases with decreasing load factors for the two generators behind the constraint. The expensive generator displays a very different picture. Its load factor remains constant as the congestion cost decreases.

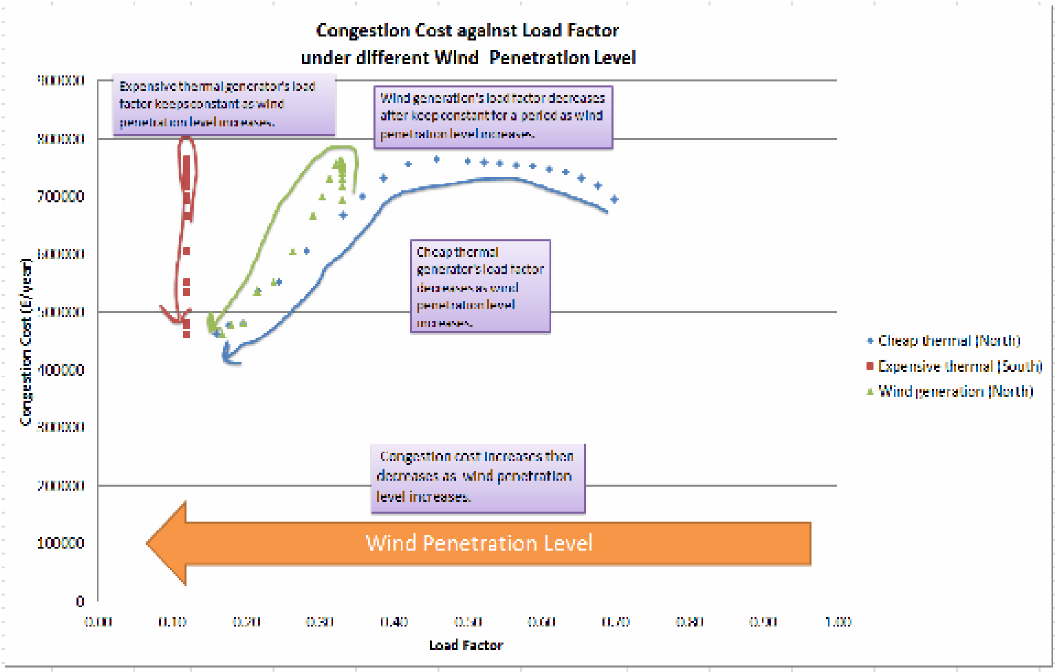


Figure 5: Congestion cost and load factor at different wind penetration levels.

The study emphasises that the load factors of thermal generators will depend upon their location relative to a transmission constraint. The expensive thermal generator that is in front of the transmission constraint has a load factor that is almost constant as the wind penetration changes. The cheaper thermal generation that is behind the transmission constraint has a load factor that decreases as the wind penetration increases and it shares the same transfer capability with the wind generation. The relationship between the expensive thermal generator load factor and the congestion cost is constant, but the relationship between cheaper thermal generator load factor and congestion cost shows a two part curve divided at the point of the peak congestion cost when wind penetration hits 0.38.

The load factor of wind generation depends on both its relative location to a network constraint and its penetration level. Before its penetration hits 0.38 and no generation curtailment is required, load factor is a constant driven by the availability of its natural resource. However, beyond the 0.38 penetration level as wind generation curtailment becomes necessary its load factor reduces as a result of the network constraints.

It is thus starkly apparent that **the relationship between load factor and congestion cost under different wind penetration level is far from linear**. One generation technology can significantly influence the load factor of another generation technology. Generalising the results from this study makes it apparent that **this relationship will vary significantly for generators of different types, locations, prices and the associated low carbon background**.

2.4 The impact of transmission capacity on congestion and load factor

The impact of the available transmission capacity on the year-round congestion cost and generator load factor was investigated by varying the transmission capacity in 5 MW steps from 100 MW to 150 MW. Figure 6 shows how congestion cost decreased as the transmission capacity increased. Figure 7 then tracks the change in the load factor for each generation technology.

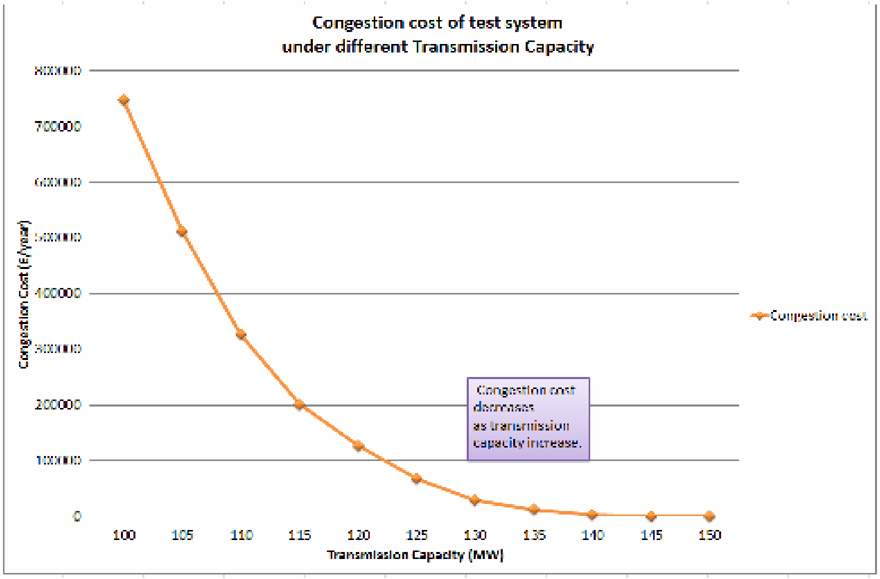


Figure 6: Congestion cost for increasing transmission capacity

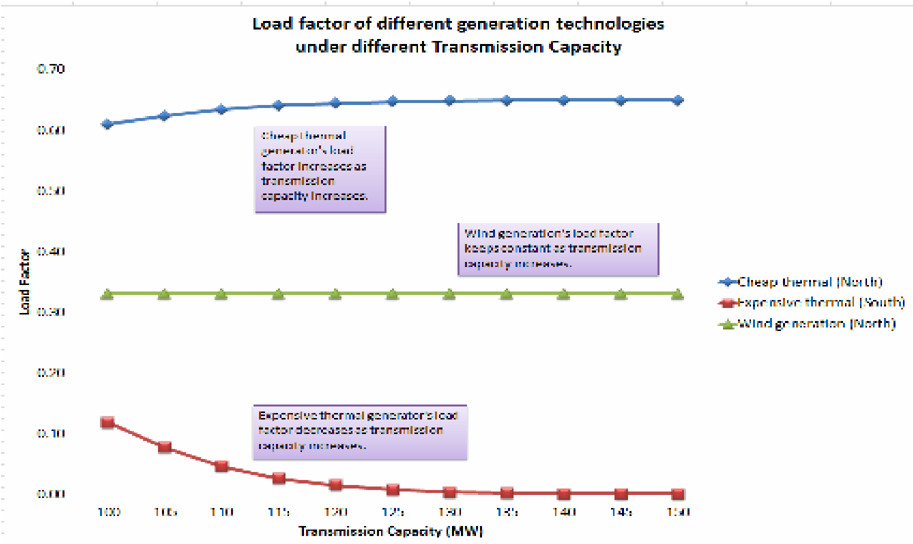


Figure 7: Load factor of generation technologies at different transmission capacity.

As transmission capacity increases the load factor of the cheaper thermal generation (blue points in Figure 7) also rises as it is able to produce more output without being constrained. Conversely the load factor of the expensive thermal generation (red points) reduces. The load factor of wind generation (green points in figure 7) remains constant with the increase in the transmission capacity reflecting the priority for its despatch. This result confirms the view that the annual load factor of individual generators is an output parameter that depends on the generator's price structure, its location, and the value of the transfer capacity between areas.

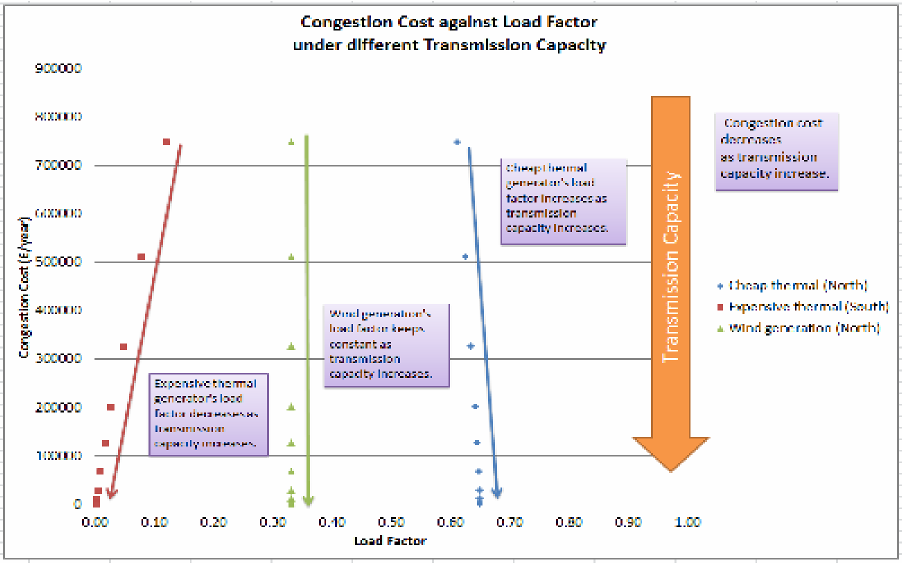


Figure 8: Congestion cost and load factor for different transmisison capacities

Figure 8 provides a scatter plot of the congestion cost for each generation technology against load factor. The trajectory for each technology shows the variation with increasing transmission capacity. Each generator technology shows a linear relationship between load factor and transmission capacity although **whether the correlation is positive or negative now depends on the location of the technology in relation to the constraint. Utilising load factor as a measure of congestion cost without recognising the location of a network constraint would clearly be a flawed assumption.**

2.5 The impact of demand load factor on congestion cost & load factor

The effect of demand load factor on the congestion cost and generator load factor is explored by varying the demand load factor between 0.63 to 0.70 times the peak demand in incremental steps of 0.01. For example this might result from an increased demand side response. In the model it is implemented by reducing the level of peak demand whilst retaining a constant level of annual consumption, thus effectively representing load shifting between time periods.

Figure 9 shows how the congestion costs increase as the demand load factor increases. Figure 10 then depicts how the load factors of the different generation technologies change as the demand load factor increases, and Figure 11 illustrates the relationship between congestion cost and generator technology load factor for changing demand load factor.

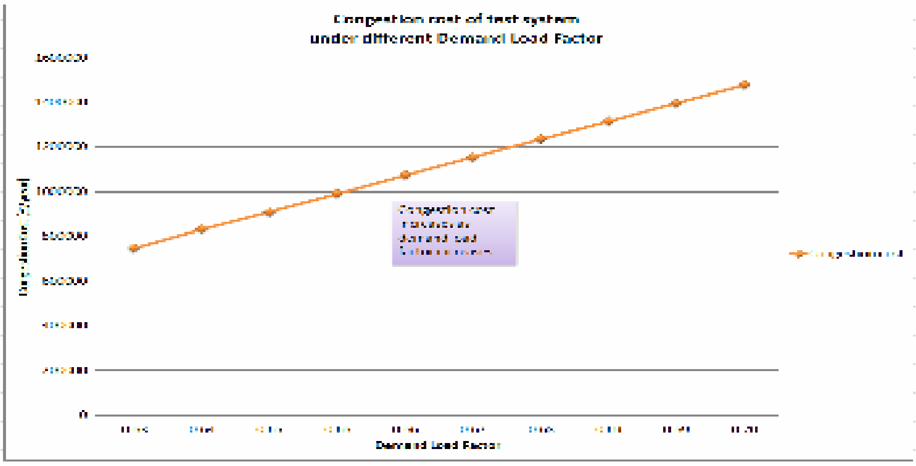


Figure 9: Change in congestion cost for increasing demand load factor.

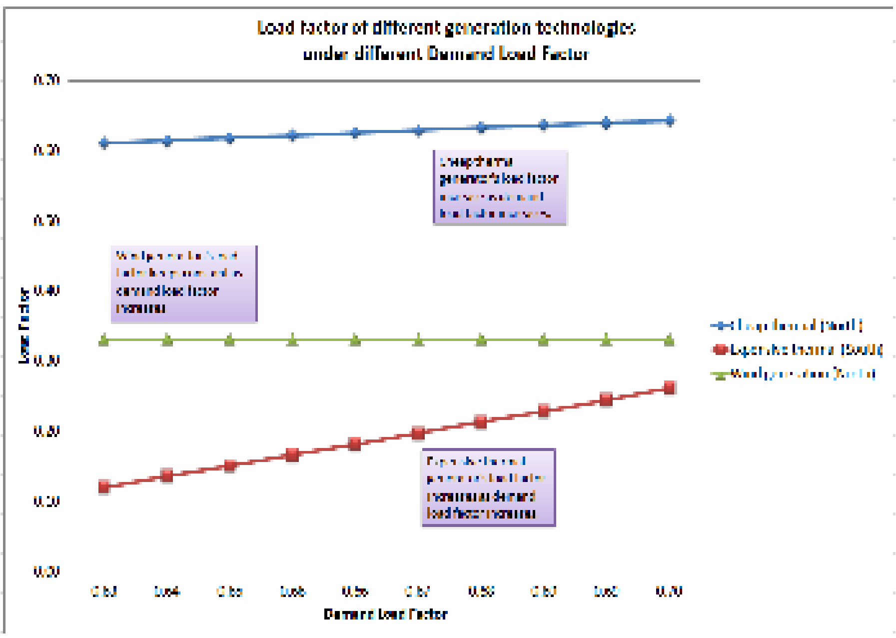


Figure 10: Generator technology load factors for increasing demand load factor

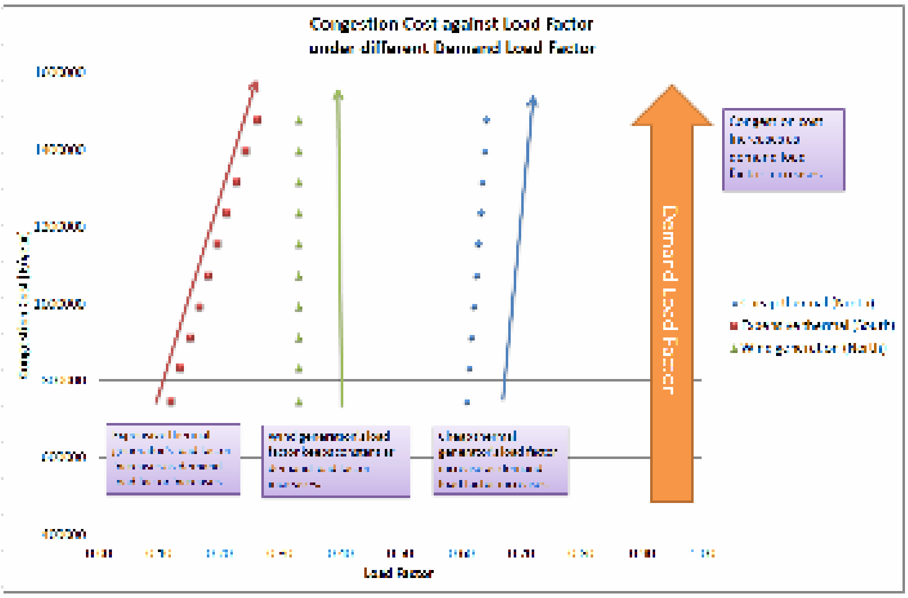


Figure 11: Congestion cost and generator load factor under different demand load factors.

In this simple 2 busbar system the relationship for each generator technology between congestion cost and generator load factor with a changing demand load factor is linear. Both the low cost thermal generation at bus 1, and the expensive thermal generation at bus 2 (respectively the blue and red points in Figures10 and 11) show an increasing congestion cost with load factor. This is because as more electricity per peak MW is required as demand load factor increases, the additional electricity has to be met by the thermal generation.

For wind generation (green points in Figures10 and 11), the installed capacity of wind generation and wind characteristics are fixed, and wind is dispatched as long as it is available. Thus the wind generator load factor is not affected by a changing demand load factor.

2.6 Conclusions

These studies have illustrated that the load factor of a single generation technology is not uniform across the system but will be shaped by different generator and demand parameters, and features of the transmission system. The costs of congestion and generator load factors are the results of these varying combinations. For generation there are a variety of technologies, production prices, generation capacities, and locations. For the transmission network there are differing transmission transfer capacities, impedances and lengths. For demand there are varying load profiles and durations, and the timing of peak demands as subsequently reflected in the demand load factor.

All these features will combine to impact congestion costs and generator load factor in different ways. Whilst based on a relatively simple representation of the GB system our studies have demonstrated that under different network, generation and demand conditions the relationship between congestion costs and load factor will vary significantly. **The relationship most certainly can not be assumed to be linear.**

Instead system congestion tends to be directional with the majority of its associated cost incurred across the B6 boundary and within Scotland, as evidenced by the figures reported by NGET. **Employing load factor as a surrogate for the cause of this congestion would smear the consequence for what is a highly localised problem across all boundaries and throughout the year. It cannot provide the necessary economic message for reducing congestion, and it certainly would not reflect the costs of congestion as required by SLC 5.5(b).**

Southern based controllable CCGT generation would be under rewarded on the basis of its annual average load factor even though it was contributing fully to the relief of system congestion. A more economically efficient arrangement would be one that targeted TNUoS charges and credits to **periods** and **locations** where generator output either **compounded** or **alleviated** congestion. However, this implies a time of use feature in TNUoS charges rather than linking congestion costs with generator class load factors within the methodology.

3. Dual versus single background for deriving TNUoS charges

3.1. Introducing the study

An important feature in the CMP213 proposals for an improved ICRP (IICRP) methodology is the introduction of dual backgrounds that reflect the trade-off between network investment and constraint costs which is now recognised in the SQSS. In the methodology that has been advanced through the working group, a Peak Security background is intended to reflect the capacity required to meet the peak demand, whilst the Year Round background is intended to reflect the year round congestion costs in the system.

As we have noted in the introductory section of this report we are concerned that NGET has been instructed to reflect the dual criteria that are now embodied in the SQSS as dual backgrounds in the charging methodology.

3.2. Study framework

For the purpose of this study a three bus network has been devised to represent the GB transmission system. Its principles features include the B6 and B15 transmission boundaries that are the most heavily congested of all system boundaries. The study derives a congestion cost duration curve for the system that indicates the degree and duration of the congestion over the 17,520 settlement periods. The study explores the characteristics of the various segments of this curve in detail, and quantifies the share of B6 and B15 congestions in each segment of the curve, and the times when the congestion is mostly likely to occur. For the year round background to create a reasonable surrogate on which to reflect the costs of the system it would be necessary for both boundaries to display a similar representation of the costs of congestion across the year. In fact the outputs from the study clearly indicate that congestion at different boundaries of the transmission network differ hugely in their magnitude, timing, and duration.

The three bus model developed for this study is shown in Figure 12. It represents the GB transmission network as three zones separated by the B6 and B15 boundaries, which together account for more that 80% of all system congestion costs. It thus provides an approximation of the year-round congestion costs in the GB power system. The two boundaries divide GB into three areas; Scotland, England & Wales (excluding Zone 15), and Zone 15.

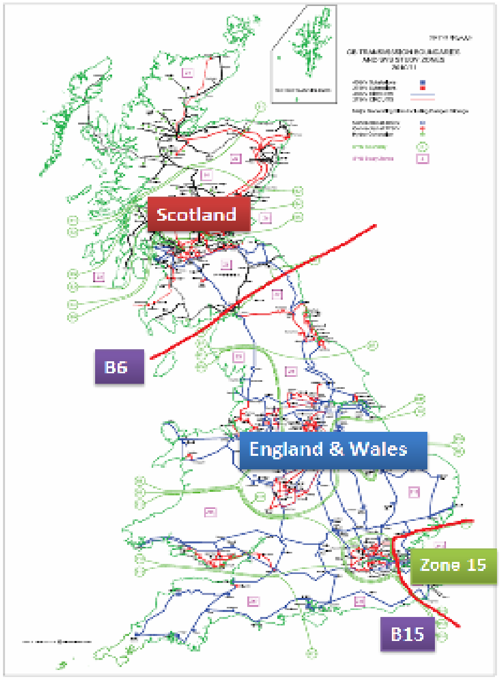


Figure 12: B6 and B15 boundaries in GB power system

The table below shows the parameters chosen to represent the features of the relevant boundaries. These have been taken from the National Grid's ELSI excel document for GB power system in 2011.

Table 5: Three-bus test system parameters

Scotland				B6 Transmission Capacity (MW)	England & Wales (exclude Z15)				B15 Transmission Capacity	Zone 15			
Generation Technology	Price (£/MWh)	Capacity (MW)	Load (MW)		Generation Technology	Price (£/MWh)	Installed capacity (MW)	Load (MW)		Generation Technology	Price (£/MWh)	Installed capacity (MW)	Load (MW)
Nuclear	6.5	2408	5697	2800	Nuclear	6.5	5713	50416	6400	Nuclear	6.5	832	2017
CCGT	39.99	1001			CCGT	45.35	19063			CCGT	43.01	2769	
Coal	37.63	2608			Coal	56.05	14757			Coal	45	2306	
Oil/OCGT	130.14	539			Oil/OCGT	171.17	4241			Oil/OCGT	150	1122	
Intermittent	0.01	2700			Intermittent	0.03	848			Intermittent	0.02	357	
Interconnector	0.01	385								Interconnector	0.001	2401	

The principal assumptions in the model are:

- Six different generation technologies are chosen for each area and the installed capacities scaled to satisfy the system peak without reliance on intermittent generation and interconnectors
- System reserve and generator availability are ignored for the purposes of this model
- The proportion of each generator technology in the total generation capacity is retained with no new capacity contemplated for any generation technology
- Wind generation output follows the historical wind speed data recorded in 2011 by the Meteorological Office
- Interconnector behaviour is simulated as generation and demand as the GB system demand changes. When demand is high (over 80% of peak), the interconnectors are deemed to be unavailable on the basis that other systems will also be experiencing high demand. When the demand is modest from 50% to 80% of peak, the interconnectors operate at their rated capacity as a generator. When the demand is below 50% of peak, the interconnectors are recognised as demand representing the exporting of power at this time
- Maximum transfer capacities for the B6 and B15 boundaries are taken as 2,800 MW and 6,400 MW respectively in accordance with their performance in 2011
- Transmission losses are ignored
- System peak demand of 58,130MW is split across the three zones with Scotland accounting for 5,697 MW, E&W for 50,416 MW, and Zone15 for 2,017 MW
- The demand profile is taken from the GB historical data for 2011 provided on the NGET website, although the same profile is assumed for each zone
- Electricity prices for each generation technology use the typical values in the ELSI excel document, with prices in Scotland and Zone 15 set lower than prices in England & Wales
- The congestion direction on B6 is from Scotland to England & Wales, and on B15 from Zone 15 to England & Wales.

The same methodology as employed for the two busbar model is followed. At times when only B6 is congested the corresponding congestion cost is allocated to B6; similarly with B15. When Both B6 and B15 are congested, the relevant power flows are used to allocate the congestion cost between B6 and B15.

3.3. Congestion cost duration curve

Figure 13 is the congestion cost duration curve derived from the analysis. It is constructed by rearranging the congestion cost observed in each settlement period from the highest to the lowest. Extremely high congestion costs only occur for a very small duration (about 12 hours), after which the congestion cost in each settlement period declines exponentially to zero.

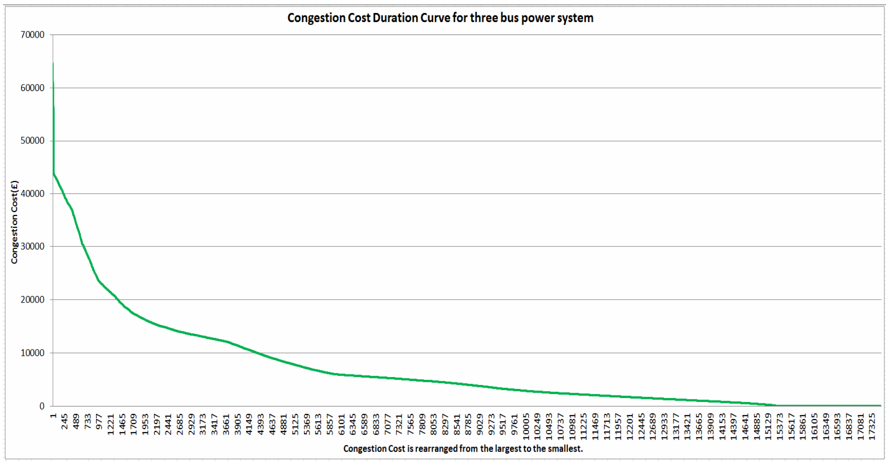


Figure 13: Congestion cost duration curve for three bus power system

The congestion duration curve can be divided into five parts representing a five piece-wise linear curve, as shown in Figure 14. The boundaries between each part are not absolute. For example some settlement periods in part 3 have the same congestion circumstances as in parts 2 and 4. The various parts are characterised by:

- Part 1 covers settlement periods when extremely high congestion costs occur. The range of congestion cost in this period is from £75,000 to £44,000 per settlement period. In these settlement periods, only the B6 boundary is congested
- Part 2 encompasses most settlement periods when both B6 and B15 are congested. The range of congestion cost is from £44,000 to £36,000
- Part 3 includes settlement periods when both boundaries are congested, or when either boundary is individually congested. The range of congestion cost in these periods is from £36,000 to £4,000.
- Part 4 includes mainly settlement periods when B15 is congested, and some when B6 is congested. The range of congestion cost is from £4,000 to £3,000.
- Part 5 includes most settlement periods when B6 is slightly congested.
- Beyond Part 5 there is no congestion for a little over 12% of the year.

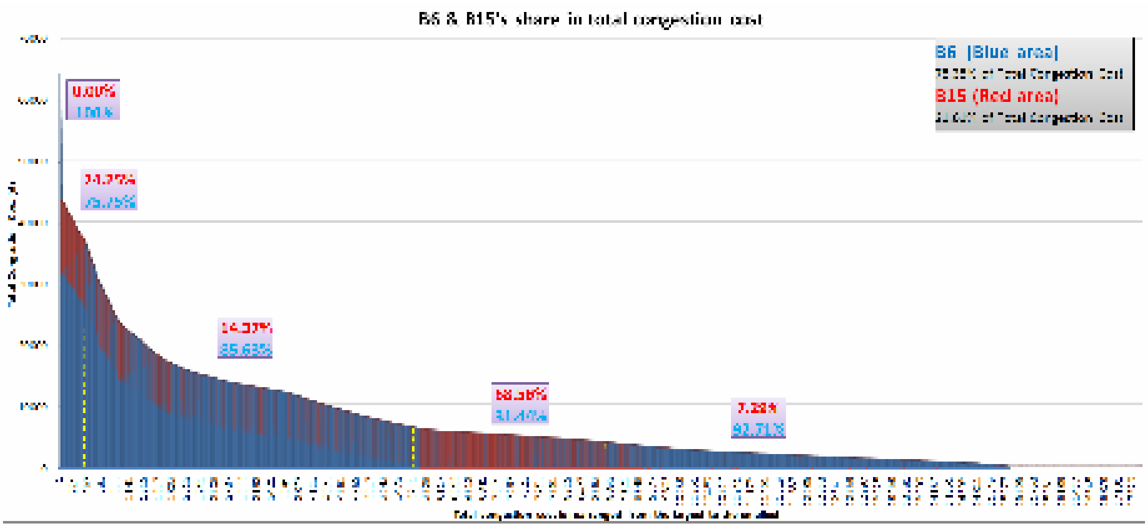


Figure 14: B6 and B15 share in total congestion cost

Table 6: Congestion between B6 and B15 under different part of congestion duration curve

	Number of settlement periods	B6 Congestion Cost £M	B15 Congestion Cost £M	Total Congestion Cost £M	Congestion share between different parts	Proportion of B6 in TCC	Proportion of B15 in TCC
Part 1	23	1.3	0	1,3	1.06%	100.00%	0.00%
Part 2	394	12.0	3.8	15.8	12.87%	75.75%	24.25%
Part 3	5427	67.4	11.3	78.7	63.91%	85.63%	14.37%
Part 4	3042	4.8	10.7	15.5	12.57%	31.44%	68.56%
Part 5	8634	10.9	0.9	11.8	9.58%	92.71%	7.29%
Total	17520	96.5	26.6	123.1	100%	78.38%	21.62%

The above table shows the share of congestion cost between B6 and B15 as determined from the areas under different parts of the congestion duration curve. The overall annual congestion cost described by the model is £123 million.

- In part 1 B6 contributes to all congested periods whilst B15 is not congested
- In part 2 when both B6 and B15 are congested their congestion cost shares are different. B6 contributes 75.8% of the congestion cost whereas B15 contributes only 24.2%.
- In part 3 B6 contributes to 85.6%, while B15 contributes 14.4%.
- In part 4 when B15 contributes to most of the congestion, the position is reversed with B15 accounting for 68.6% of the total whilst B6 accounts for only 34.4%.

- In part 5 when B6 is slightly congested in most of settlement periods, B6 become dominated again at 92.7% of the total.
- Overall the B6 boundary incurs 78.4% of the total congestion cost, and B15 21.6%.

The different parts of the congestion cost duration curve reflect different congestion scenarios. Under different scenarios, the role of the same generator may change. A generator which contributes to congestion within one scenario may help eliminate congestion in another scenario. Even for the simple three bus representation of the GB transmission system it is necessary to have at least five different congestion periods to reflect the various aspects of year round congestion. The inevitable conclusion is that employing only two backgrounds is wholly inadequate in producing even the crudest representation of system performance and costs.

3.4. The nature of boundary congestion

The following figures explore the intensity, location and timing of congestion costs as derived from the 3-bus model. The first figure is a plot of congestion cost for each settlement period from 1st Jan 2011 to 31st Dec 2011, and the second indicates the same picture but as a scatter diagram to separate the various points. A colour code is used to distinguish periods when only the B6 boundary is congested (blue points) from times when only the B15 boundary is congested (red points) and times when both boundaries are congested (green points). In general the congestion across the B6 boundary is significantly higher than across the B15 boundary. These diagrams illustrate that congestion is not uniform across the system.

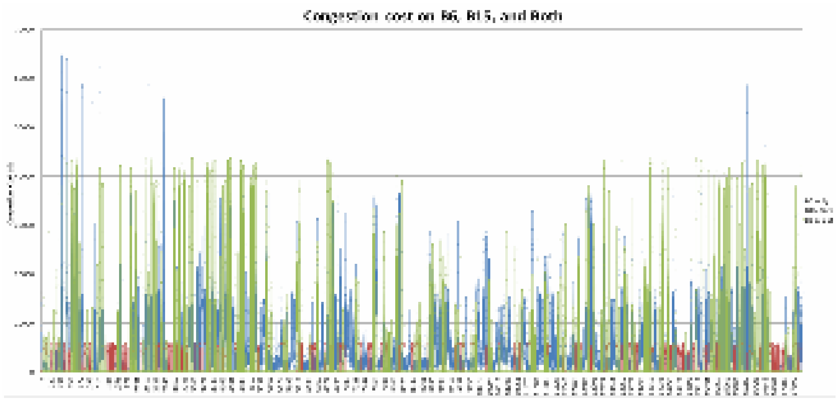


Figure 15: Year round congestion cost over the system

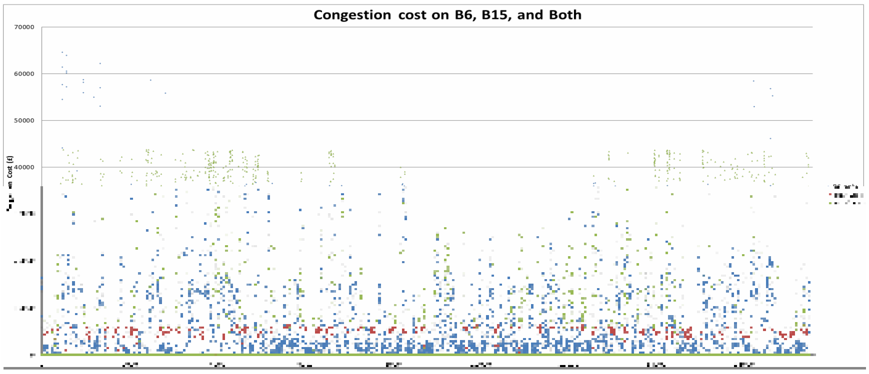


Figure 16: Scatter plot of year round congestion

The following three figures further illustrate the diversity in the timing of the congestion periods during calendar 2011 by indicating the times of congestion at the B6 boundary, the B15 boundary, and when both boundaries are congested.

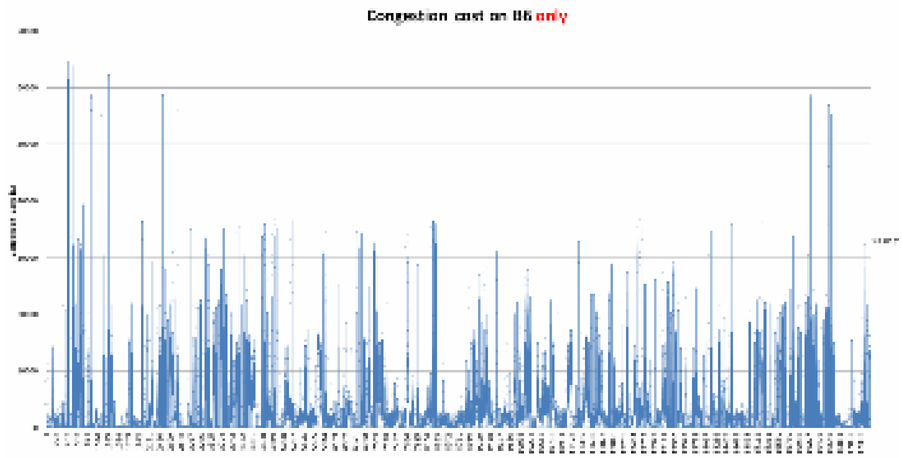


Figure 17: Year round congestion on B6 only

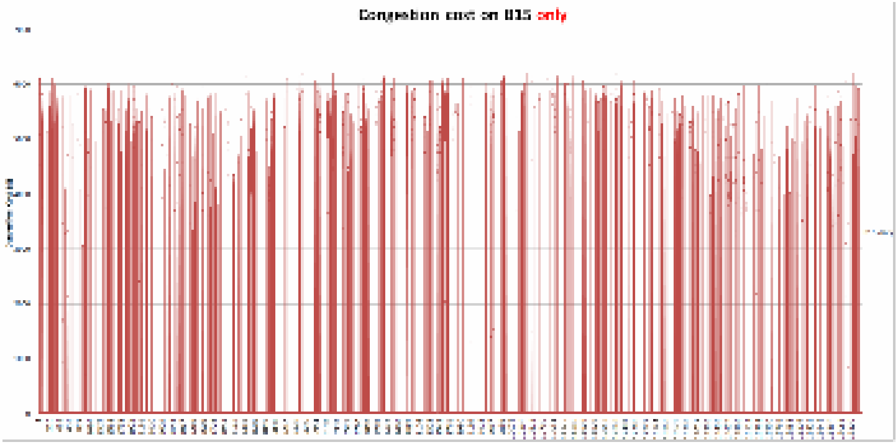


Figure 18: Year round congestion on B15 only

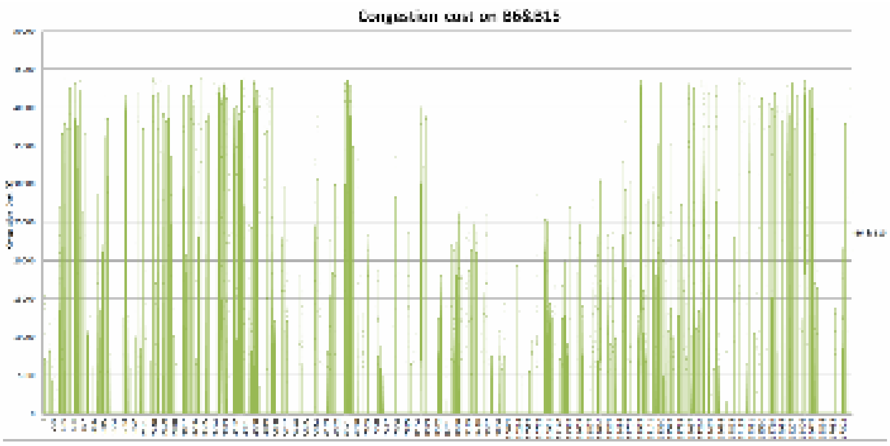


Figure 19: Year round congestion of B6 & B15 together

The proportion of time the boundaries are congested, either singly or together are tabulated below. The probability that congestion will occur on a 3-bus representation of the GB system is 87.8%, although the B6 boundary is responsible for more than 80% of this figure.

Table 7: Proportion of time each boundary is congested

Congestion situation	Number of settlement periods	Proportion in all settlement periods	Proportion in congested settlement periods
System	15,379	87. 8%	100.0%
B6 Only	11,018	62.9%	71.6%
B15 Only	2229	12.7%	14.5%
B6 & B15	2132	12.2%	13.9%

3.5. The timing of congestion

The next five figures explore the frequency and time of day when congestion is arising at each boundary, or combination of boundaries, for each part of the congestion cost duration curve shown in Figure 1.

Figure 20: Part 1 - Frequency and timing of congested settlement periods

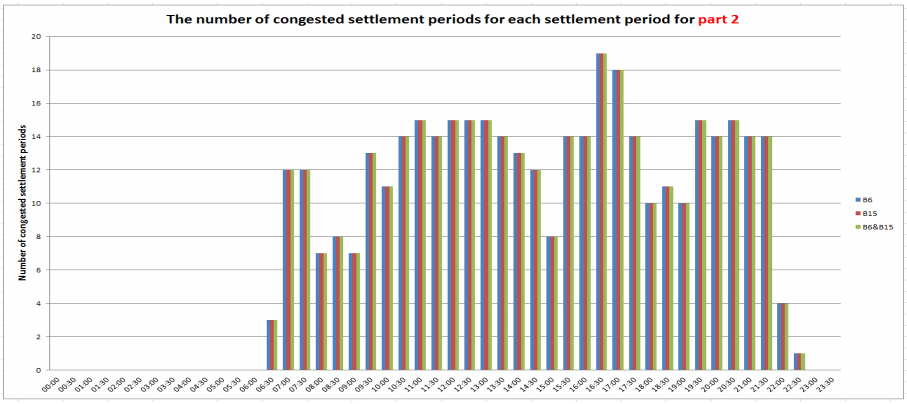


Figure 21: Part 2 - Frequency and timing of congested settlement periods

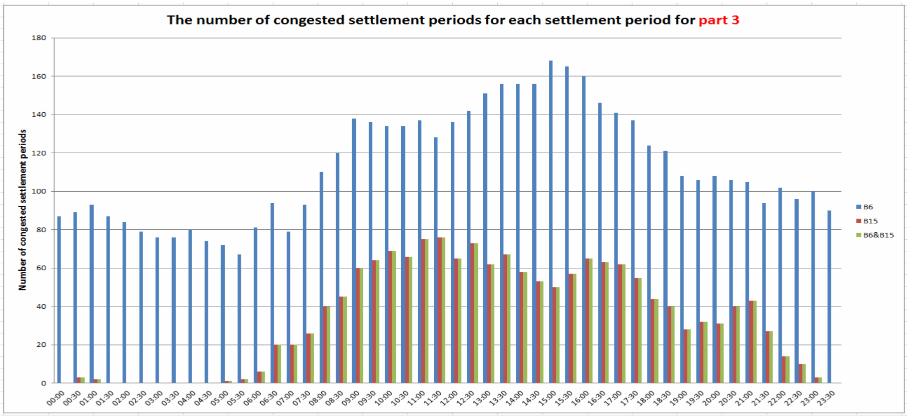


Figure 22: Part 3 - Frequency and timing of congested settlement periods

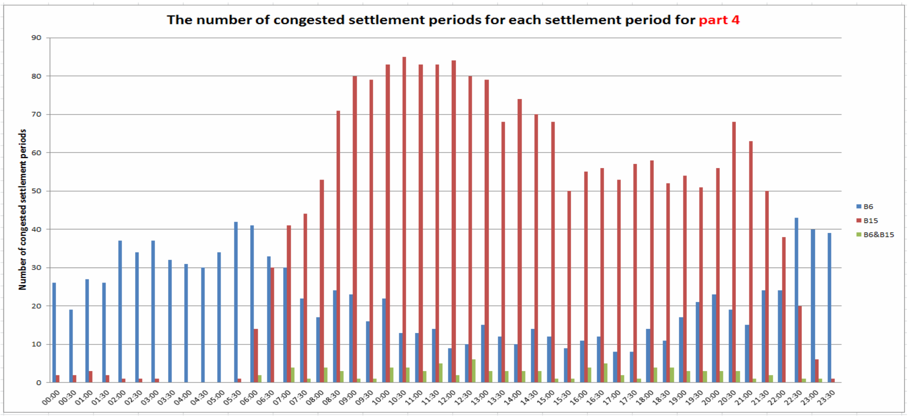


Figure 23: Part 4 - Frequency and timing of congested settlement periods

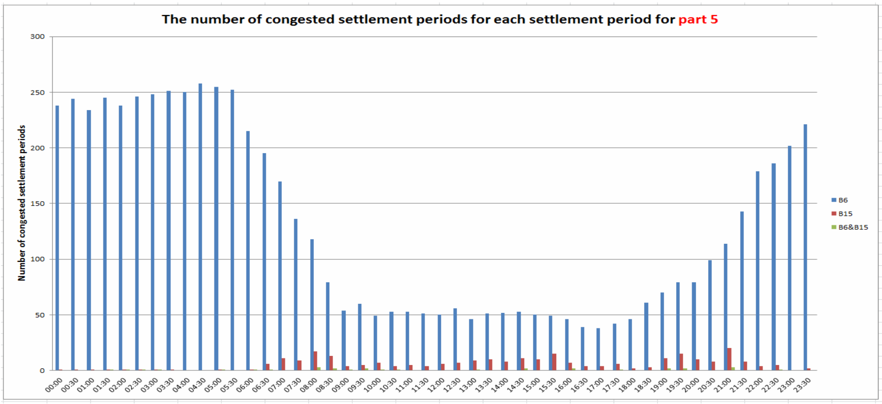


Figure 24: Part 5 - Frequency and timing of congested settlement periods

Part 1 of the congestion cost duration curve demonstrates exceptionally high levels of cost but these are focussed into the six settlement periods around the system peak. They are associated exclusively with the B6 boundary.

In part 2 of the congestion curve, when both boundaries are congested the timing of the congestion becomes more diffuse but is still associated with the day time and evening hours.

Over part 3 of the curve the frequency of congestion on the B6 boundary tends to appear like the typical daily load curve, whereas the B15 boundary is only congested during daytime and evening hours as it was in part 2. When B15 is congested then B6 is generally congested also. The B15 congestion may be affected by the interconnector assumption which is assumed to be exporting power when demand is high.

During part 4 of the curve the B15 boundary shows the same pattern of congestion as for part 3 but the B6 boundary becomes congested mainly during off-peak hours. The incidence when both boundaries are simultaneously congested becomes relatively small.

Finally in part 5 of the curve the congestion of the B15 boundary falls away. The predominance of congestion across the B6 boundary now migrates to the off peak settlement periods.

3.6. Conclusions

In this section, we have illustrated that year-round congestion costs is not uniform across the system but varies significantly in magnitude, time and boundary location. These differences in congestion magnitude, time, and location are not reflected in the CMP213 proposals. Rather, the use of a single year-round scenario at the time of peak generation outputs and annual load factor to reflect year-round congestion costs essentially assumes that all boundaries have the same level of congestion throughout the year. Employing load factor as a surrogate for the cause of congestion would smear the consequence for one boundary across all boundaries and in all time periods. It cannot provide the necessary economic message for reducing congestion, and it certainly will not reflect the costs of congestion in accordance with SLC 5.5. The inevitable consequence of adopting the IICRP proposals is a further increase in congestion cost, which is in direct opposition to the purpose of project Transmit.

An arrangement that could target TNUoS charges and credits in periods and locations where generator output either contributes to, or relieves congestion would be a constructive approach. However, this implies a time of use feature in TNUoS charges that is developed against multiple backgrounds rather than simplistically linking it to generator annual load factors.

However if multiple background with their respective time periods and duration are judged to be too complicated then the existing ICRP method should be retained for the sake of ease of understanding rather than further dilute the economic signal. This would be a better solution that would accord with the principles of cost reflection, rather than creating a dual background which would be a retrograde step in the reflection of costs and the provision of useful economic signals.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Respondent:	Mike Woods
Company Name:	BVG Associates
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We believe WACM number 7 is the best overall option. Justifications against the main constituent parts of the Original and the WACM's are as follows: **Sharing – no diversity** Evidence base for ALF link to incremental constraint costs is strong, and a more consistent and long lasting relationship than other shorter term effects of bid price and diversity of plant in an area. Support no diversity overall as improves cost reflectivity without excessive complexity and links variability in charges with variability in useage, which is manageable by generators. **Sharing – diversity method 1** Impact of diversity on incremental costs has been demonstrated in principle, but concerned that all Diversity methods whilst attempting to improve the resolution of cost signals (i.e. average ALF to more specific targeting on zones) require some subjective assumptions for what is a complex and changing picture, so improvement in accuracy is debateable. Furthermore, the variability of charges being linked to diversity cannot be managed by generators as they have no control over where other generators locate. Of the three methods, Diversity method 1 employs LC/C assumptions but does not cap sharing at 50% (see Diversity 2 for comment on this), and it also avoids any on/off sharing signals for boundaries. On that basis, Diversity 1 is considered to be an improvement on the baseline but not an improvement on options with no diversity. **Sharing – diversity method 2** Methods 2 and 3 Diversity rather arbitrarily limit sharing at 50%, for which there is no empirical evidence. Therefore feel it is a step too far and requires more evidence. **Sharing – diversity method 3** As Diversity 2

	Form of sharing – ALF 5 year historic Transparent, employs user data and practical **Form of sharing – hybrid** Less practical to implement than historic ALF but recognise why some generators would prefer it **Parallel HVDC and islands – Specific expansion factor (EF) targeting 100% of Converter costs** Targeting 100% of the costs locationally is inequitable with cost allocation in existing mainland expansion factors, and inconsistent with TNUoS principles which do not target fixed costs. **Parallel HVDC and islands – Specific EF, Generic 40% targeting of Converter costs for AC substation equivalence and Quad Booster-like benefits** Removing these costs achieves better parity with existing expansion factors and is more consistent with TNUoS methodology. **Parallel HVDC and islands – Specific EF, generic 50% targeting of converter costs for AC substation equivalence** Whilst this option does recognise equivalence on treatment of AC substations it does not attempt to target other fixed costs in the AC system. **Parallel HVDC and islands – Specific EF, target according to removal of the exact cost of AC equivalent costs in each converter station** As above, although recognise enhanced cost reflectivity of specific treatment, suspect cost breakdown will not be practicable to obtain.

Do you support the proposed implementation approach? If not, please state why and provide an alternative	In terms of implementation date, we favour a 1 April 2014 implementation date, which, we note, is already delayed from the original Project TransmiT timetable. We would not wish implementation to be delayed for one or two

suggestion where possible.	players and would hope the impact could be managed on a case-by-case basis.
Do you have any other comments?	We acknowledge the work that National Grid has put into producing these results for the Code Administrator consultation. Whilst we feel that the results are sufficient to understand the broad direction of travel of impacts, we do feel that the results would be enhanced by some commentary for those parties interested in interpreting the results in the context of the modelling methodology. We welcome National Grid's commitment to do this via their own response to the Code Administrator consultation, and would welcome the opportunity for any clarifications arising via TCMF or some other informal forum, before Ofgem's own impact assessment.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

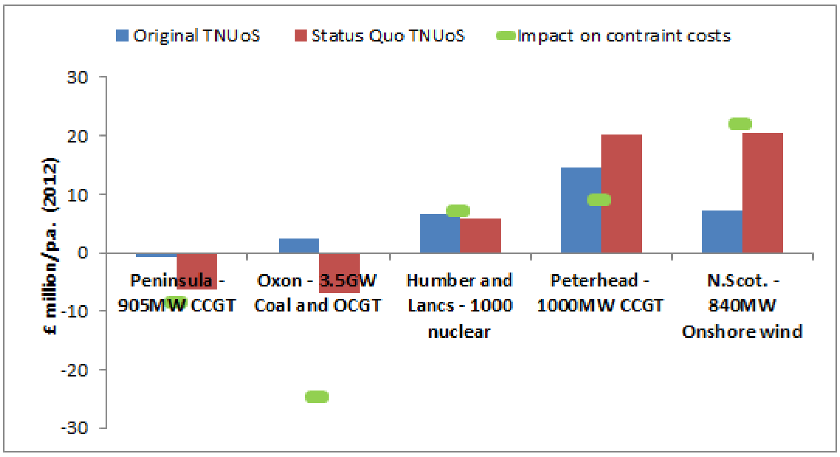
Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	Ricky Hill (ricky.hill@centrica.com)
Company Name:	Centrica
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology are:* *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.* **No. We do not believe that the original, or the alternatives in their current state, better facilitate the Applicable CUSC Objectives. Whilst the alternatives go some way to improving some of the oversimplifications inherent in the original, namely by taking generation diversity into account, this is done in an imperfect way which needs to be rectified before they can be considered with equal standing alongside the status quo and original. In addition to this issue, the stage 2 Impact Assessment has a number of contradictory and anomalous results which hinder parties' ability to accurately measure the impact of the various options and assess them against the applicable CUSC objectives.**

	Our ultimate conclusion is that Working Group has not fulfilled the terms of reference as set out by the CUSC Panel in July 2012, especially with respect to paragraph 5 (k) in the scope of work to "consider and undertake appropriate economic analysis including the impact on current and future customers on a national and regional basis" and paragraph 6 which stipulates that the "Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs)". It is for this reason that we ask the CUSC panel and / or Ofgem to request that the Work Group reconvene in order to address these issues. **Please find our detailed reasoning below.** **Original** **Sharing** The application of Annual Load Factor (ALF), the tool that the original uses to reflect sharing on the network, would negatively impact cost reflectivity and competition due to the unjustified weakening of locational signal in tariffs and the subsequent baseless significant financial transfers that would take place between parties subject to TNUoS. In this respect it would not better meet **CUSC objectives a) and b**). Furthermore, we believe that the application of ALF could be discriminatory because it scales charges in the same way for all generators whether or not sharing is taking place on the network. An array of evidence has been provided to demonstrate that the core assumption in the original, that individual generators' load factor is a robust proxy for incremental constraint costs, is seriously flawed in the overly simplistic way in which it is done. The modelling undertaken by the University of Bath demonstrated that under different network, generation and demand conditions the relationship between constraint costs and load factor varies significantly. They conclude that "it is impossible to infer that by assuming linearity between load factor and constraint costs the charging methodology will be enhanced; unless account is also taken of other factors such as location, efficiency, market conditions, and critically, the network transfer capability". The majority of constraint costs (defined as congestion costs in the Bath University report) in GB are incurred across the B6 boundary and within Scotland. However, employing load factor in TNUoS as proposed in the original assumes that all boundaries have the same level of congestion at all times in the year. This will under-represent a generator's contribution to congestion costs in northern areas and over-represent costs in southern areas. As the Bath University analysis concludes, "southern based controllable CCGT generation would be under rewarded on the basis of its annual average load factor even though it was contributing fully to the relief of system congestion". We believe National Grid's ELSI model also demonstrates that southern plant would under-rewarded under the original and hence would be less cost reflective. Using the ELSI model we calculated the impact on constraint costs of removing generators from the network. Analysis confirms that in negative zones (Peninsula and Oxon. in the chart) the original understates the benefit that these

	stations provide in terms of reduced constraint costs. By the other token, the original provides too high a discount to wind generators in the north of Scotland relative to their system impact.  The locational signal in negative zones and the South of GB appears significantly less cost-reflective than the current TNUoS methodology. For example, removing Langage power station (Peninsula in the chart) from the ELSI model causes a system-wide increase in constraint costs of £9 million per annum. This is closer to the status quo TNUoS credit of £6 million per annum than the approx. £1 million per annum proposed under the original. The conclusion is the original cannot be considered to be more cost-reflective than the status quo. Furthermore, we do not believe that the introduction of a 'year-round' background and ALF in the charging methodology is a cost-reflective follow-on from the introduction of an Economy Criterion in the NETSQSS. This also appears to have been Ofgem's view in its decision on GSR009 in November 2011, when it stated that the NETSQSS changes do not "have any direct implications for charging". The NETSQSS changes appear largely theoretical, and as recognised in the Ofgem decision, do not alter the costs of building and operating the transmission network. Ofgem also recognised that investment decisions will continue to be based on more than simply applying the NETSQSS rules and that the changes were expected to result in a 'first-pass' assessment. Large investments will subject to more detailed cost benefit analysis and there will also be wider consideration of other factors such as impact on overall security of supply, and facilitation for future development of various types of generation. Also, the way in which the original interprets the "dual criteria" changes to the NETSQSS as a "dual background" is flawed. The original uses peak demand to bin (or allocate) both 'peak' and 'year-round' circuits which does not seem appropriate with respect to the calculation of the latter tariff. The 'year-round' tariff is supposed to reflect the second criterion in the GSR009 changes which introduces an economy criterion that requires that sufficient transmission system capacity be provided to accommodate all types of generation in order to meet <u>varying levels of demand efficiently</u>. In summary, as calculated in the original, we do not believe that the dual tariff results in an incremental signal that is meaningful or accurately replicates the aims of the NETSQSS changes undertaken through GSR009.

	We also do not believe that the original better meets the applicable **CUSC objective c),** which is to take into account developments in transmission licensees' transmission businesses. Key reasons for this are: • Investment Cost Related Pricing as a charging methodology does not reflect actual investment decisions. It does not make any assumptions about the underlying transmission network and assumes that generation will always necessitate network reinforcement. The original is no different in this respect, except that is distorts the locational signal by applying load factor to charges. • The assumption of a linear relationship between load factor and incremental constraint costs is based on the supposition that the network has been built on an optimal basis. The size of the transmission network relative to generation is not uniform across the country which is why the level of congestion across the network is not uniform, as we have proven. Also, Connect and Manage policy which enables generation to connect before sufficient wider transmission is built is another reason why the network is not currently built on an optimal basis. **Alternatives** We welcome the work that the Working Group has undertaken on developing alternatives which recognise and seek to address some of the flaws of the original. Including generation diversity as a variable goes some way in overcoming the load factor simplifications assumed in the original. However, the development and evaluation of the alternatives was rushed in the Working Group due to time pressures, and as such, it is clear that the alternatives have not been developed to the same level as the Original. This makes it very difficult for us (and presumably for Ofgem and the CUSC panel) to conclude that they better meet the CUSC objectives. Each of the methods has a number of outstanding questions which whilst discussed by the Working group have not been fully resolved. On the specific alternatives, Method 1 fails woefully as it only accounts for diversity in exporting zones. Our analysis has shown that load factor is not an accurate proxy for incremental constraint costs in importing zones and as such any diversity option would need to take account of this. We also agree with some in the Work Group that the true benefit of small volumes of carbon in a predominately low-carbon area would not be adequately recognised under this option, as all generation behind a boundary would be subject to the same overall sharing factor past the 50% sharing point. Methods 2 and 3, whilst much better than Method 1, both contain an arbitrary 50% capping of the sharing element. We believe that the rationale for the 50% is weak and, furthermore, there is no justification why 50% caps on sharing should apply in methods 2 and 3 but not in method 1. Capping the amount of deemed sharing at a maximum 50% based on the fact that “maximum sharing occurs when a TNUoS zone contains an equal capacity of both low carbon and carbon generation and that the optimum transmission boundary capacity would be 50% of the combined

	capacities" is flawed. We can assume a case where two 100MW generators (G1 ad G2) are sharing a 100MW transmission asset. G1 is running at full capacity and G2 is turned off and they then swap, such that G1 is turned off and G2 is running at full capacity. It is evident that 100% sharing has taken place. In addition, we believe that method 3 warrants further consideration in the area of the zonal sharing factors. In particular whether it would be more granular sharing factors would be more appropriate, for example by breaking sharing factors down for individual groups of generation of a similar type in an area. It could be argued that this would make this method more cost reflective. A generic limitation in all of the alternatives is that, as the Bath University study has demonstrated, there are other drivers of constraint costs which need to be considered, such as different network, generation and demand conditions. It would be our preference any convened Working Group would also examine these drivers. As it stands we believe that method 1 should not be taken forward for the reasons given and that methods 2 and 3 should be sent back to the Working Group in order to address the issues raised above. **HVDC and island links** Centrica believes that HVDC circuits should be incorporated into charging methodology in a way which most accurately reflects the associated costs and is consistent with the rest of the charging methodology. We believe that the original achieves this by including 100% of the cost of the sub-sea cables and converter stations in the expansion factor and hence best meets the applicable CUSC objectives. This methodology is also consistent with offshore links. In terms of island links, we also believe the approach set out in the original would best meet the applicable CUSC objectives. We believe that this approach, whereby new expansion factors would be calculated for each type of transmission technology and the locational security factor would be adjusted to reflect redundancy provided on the link offers the most cost-reflective solution at the current time and would be consistent with the physical nature of the transmission asset. As with HVDC links, we believe that 100% of the converter stations should be included in the expansion factor for HVDC island link. **Impact Assessment** The Direction issued by the Authority to National Grid in relation to the Project TransmiT required National Grid to ensure that any Modification proposals developed were supported by a robust evidence base. This was also replicated in the Working Group terms of reference. We not believe that the stage 2 Impact Assessment undertaken is of sufficiently robust nature for it to be considered that this requirement has been fulfilled. Whilst we note that National Grid is planning to publish a 'refined' Impact Assessment in their response to this consultation, we do not believe that industry parties currently have an accurate assessment which the can measure the original and

	alternatives against. There are a number of areas where improvement is required to the Impact Assessment to make it useful: • The stage 2 Impact Assessment has produced indicative tariffs for the original and alternatives which are inconsistent with earlier indicative tariffs, appear illogical, and are inconsistent between options. We understand from National Grid that due to differing 'underlying drivers' these tariffs could not be used for parties to accurately measure, say, the impact of method 1 versus the impact of method 2. • The lack of commentary on the vast arrays of data significantly reduces its usefulness. This is especially lacking in areas where the National Grid results contradict those of Redpoint and further explanation is required. For example, the Redpoint modelling undertaken in 2011 demonstrated that the original would have £1.4 billion predicted impact on consumers' bills to 2030 relative to the status quo. This would seem logical and consistent with the weakening of the signal to locate in economically efficient areas. However, the National Grid stage 2 modelling shows a £10.6 billion benefit over the same period. The National Grid modelling also shows a £2.6 billion reduction in transmission build under the original relative to the status quo. For a weakening of the locational signal to actual reduce transmission spend defies logic and requires further explanation. • The Impact Assessment has produced some anomalous tariffs, which whilst may be outliers, undermine confidence in the rest of the data. For example, in 2024 there is an anomaly in the modelled tariffs whereby all the generation tariffs are negative. Also, on some of the data sets there are significant inconsistencies between years. This is especially apparent on the consumer bill impact. **The way forward** For the reasons mentioned above we believe it is essential that the CUSC panel and / or Ofgem request that the Work Group reconvene in order to address these issues listed above. Given the significant resources that industry, Ofgem and National Grid have invested in this process we believe it would be a sub-optimal outcome if a methodology is implemented or alternatives are discounted which the Working Group has not had chance to fully develop and / or the impacts are not fully understood. As we believe an April 2014 implementation date is now largely unfeasible, as well as inappropriate, the various stakeholders have sufficient opportunity to revisit these proposals.

Do you support the proposed implementation approach? If	Whilst we do not support CMP213 as it stands, option 4 (April 2015) is in our view the most appropriate date for

not, please state why and provide an alternative suggestion where possible.	implementation. The technical feasibility of an April 2014 implementation is wholly dependent on strict deadlines being met. In addition, assuming April 2014 is technically possible, it does not provide generators with sufficient foresight to react to the change in signal. This could partially be overcome by reducing the required notice period to amend TEC levels, but it would not provide sufficient notice to generators to deal with other issues including site closures with associated redundancies and the unwinding of power purchase contracts. An April 2015 implementation date is also necessary to enable the Working Group to further develop the alternatives and to better understand the impacts of the various options.
Do you have any other comments?	We also submit the Bath University report we commissioned along with RWE, “Year-round System Congestion Costs - Key Drivers and Key Driving Conditions”.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Cem Suleyman – cem.suleyman@draxpower.com*
Company Name:	*Drax Power Limited*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	The views contained in this response are mostly underpinned by standard economic and charging principles, rather than the modelling outputs produced by National Grid. This is because we believe further work is required to test the outputs produced by the modelling to ensure their robustness. We note a number of shortfalls in the analysis and omissions in the data provided. As such, the analysis and resulting outputs should be thoroughly scrutinised by the CUSC Panel and Ofgem to ensure that a decision can be taken on the back of the data made available. We believe the majority of these issues have been discussed by the Workgroup, although we note some extra concerns following additional scrutiny during the consultation period. The key issues we would like to highlight, which will need to be tested/explored further by National Grid / Ofgem prior to a decision, can be found in the 'any other comments' section below. We also note here that National Grid intends to provide updated modelling analysis as part of its submission to the Code Administrator Consultation. This is far from ideal and is not fitting with the spirit of industry code modification processes. Respondents to this consultation would have benefitted from the best possible information available to inform their written submissions. Any additional or modified analysis / data should have been made available for industry scrutiny. For the reasons above, the views provided in this response may be subject to change should new data reveal significant effects that have not been previously considered and/or challenge previously understood effects and relationships.

	Tariff predictability An important aspect which informs our views on the different options developed is the degree to which tariff predictability is affected by different charging methodologies. Ensuring that market participants are able to forecast significant changes to their cost structure (including TNUoS charges) is essential in ensuring parties are able to react to price signals in an efficient manner. We believe that all the Sharing options developed introduce a degree of additional complexity to the charging methodology. The use of an ALF scaling factor and/or determining generation plant diversity are likely to further restrict users' ability to predict future tariff changes. This is likely to impact on the efficiency and competitiveness of the sector. A further issue to note is that the use of a two part background and, consequently, the development of a two part tariff, may lead to increased charging volatility for peak tariffs. Specifically, as the generation mix changes in future years, with an increase in intermittent generation capacity, this capacity will not be exposed to the peak tariff. Therefore the charging base for peak security is likely to shrink, making peak tariffs increasingly susceptible to small changes in capacity entering and exiting the system. The resulting volatility of peak tariffs will be difficult to manage for those parties who pay peak charges. As such, there must be a significant benefit in terms of improved cost reflectivity which justifies the increase in the complexity of the charging arrangements. We include an evaluation of this trade-off below for all the Sharing options. We provide views below on the 11 individual components which make up the Original and 26 WACMs. This provides a basis for our views on the 27 options presented against the Applicable CUSC Objectives (ACOs). **Sharing** 1. <u>No Diversity</u> It is clear that a number of different factors affect the level of congestion costs incurred by National Grid. These include load factor, the correlation between generation running within a zone (or across zones), the correlation with the timing of a system constraint(s), bid and offer prices made available, etc. As such, to distinguish the supposed different costs imposed by different technologies based solely on load factor, thereby ignoring other important impacts (such as plant diversity), does not seem to represent an improvement in terms of cost reflectivity relative to the Baseline. Both the Original and Baseline appear just as bad in attempting to reflect the different costs imposed by different generation technologies. The deficiency in relying solely on load factor to distinguish

	between different costs imposed by different generation types is demonstrated clearly by the load factor/congestion cost analysis. It suggests that the proposed linear relationship between the two deteriorates in areas on the extremities of the system, where one generation plant type dominates (i.e. there is little diversity of generation types). This effect is particularly apparent in areas where the concentrated generation type in question provides expensive bid prices. Moreover, this relatively crude attempt to increase cost reflectivity will increase the complexity of the charging arrangements (in particular the use of an ALF scaling factor), affecting the ability of parties to predict future changes in TNUoS charges, and thus impacting the efficiency of the market and competition. As a result, we believe that options which do not take account of plant diversity do not represent an improvement against ACOs A and B. As such The Original and WACMs 1, 7, 14, 21, 22, and 28 do not better facilitate ACOs A and B. 2. <u>Diversity Method 1</u> Diversity Method 1 represents an improvement on the Original in that it better reflects sharing on the transmission system, in particularly taking account of plant diversity. We also note that the proposed 'Low Carbon' / 'Carbon' split is adequate for the purposes of all the Diversity options. However, Method 1 fails to give equal weight to different technology types in terms of the sharing benefits that both 'Carbon' and 'Low Carbon' plant provides. Specifically, there is no evidence to suggest that 'Low Carbon' plant is more important in terms of ensuring reduced transmission build and/or providing system sharing benefits relative to 'Carbon' plant, i.e. in effect, too much of either technology is likely to drive increased transmission costs, be it the cost associated with reinforcing the network or costs associated with congestion. As such this option does not seem to represent a significant improvement in terms of cost reflectivity relative to the Baseline. This, coupled with the increased complexity associated with this option (in particular the ALF sharing factor), means we do not believe it better facilitates ACOs A and B. As such WACMs 2, 5, 9, 12, 16, 19, 23, 26, 30, 33 and 40 do not better facilitate ACOs A and B. 3. <u>Diversity Method 2</u> Diversity Method 2 represents a further improvement on the Original and Diversity 1, in that it best reflects sharing on the transmission system. Unlike Method 1, it treats 'Low Carbon' and 'Carbon' plant equivalently. This is because 'Carbon' and 'Low Carbon' plant are prorated on an equal basis, i.e. increasing proportions of 'Low Carbon' plant reduce shared MWkm in the same way that increasing proportions of 'Carbon' plant does. This potentially represents an improvement on the Baseline, subject to the employment of the scaling factor (please see

	below for further details) and the increase in complexity of the charging arrangements. 4. <u>Diversity Method 3</u> Diversity Method 3 is very similar to Diversity Method 2 and as such shares the same qualities associated with it. The main difference is that it only applies a single background (Year Round, rather than Peak and Year Round). We are not convinced that the use of different backgrounds, reflecting changes to the SQSS, materially improves the cost reflectivity of TNUoS tariffs. On the contrary, the use of a single background is simpler and may provide benefits in terms of minimising tariff unpredictably/volatility (please note how, as described above, the use of a dual background may drive greater peak tariff volatility). Therefore, Diversity Methods 2 and 3 have the potential to better meet ACOs A and B by increasing cost reflectivity and thus facilitate efficient competition. However, this improvement is tempered by an increase in the complexity of the charging arrangements. **However, the four methods noted above need to be considered in conjunction with the sharing factor that is used to derive final user tariffs. It is the proposed application of the sharing factors (developed by the Workgroup) that is of greatest concern to Drax. We discuss these concerns below.** 5. <u>Year Round – Annual Load Factor historic specific (5 years)</u> The use of the Annual Load Factor (ALF) scaling factor will introduce unnecessary complexity into the wholesale market. This is due to a new short-run behavioural signal being created as a result of introducing ALF into the TNUoS charging methodology. Generators will have to consider how to factor in future increases / decreases in transmission charges, which occur due to a change in their output, into their Short Run Marginal Cost (SRMC) calculation. In short, ALF creates a new variable cost of generation. The lagging effect inherent in the ALF calculation makes it very difficult for generators to accurately value this variable cost, which is likely to impact the efficiency of the wholesale market. This effect is outlined in Annex 14.1 of the consultation. It is argued that the use of a generator specific scaling factor is required to ensure sufficiently cost reflective charges. However, it has never been articulated what signal the use of a specific ALF scaling factor provides generation and how generation is supposed to react to this signal. As such, it is unclear how the proposed signal will translate into helping to optimise total power system costs (generation and transmission). It is far from clear how the perceived increase in cost reflectivity will drive benefits for competition and end consumers. Overall, we conclude that the potential benefits outlined above

	associated with Diversity 2 are far outweighed by the disadvantages associated with the ALF methodology. Consequently, the No Diversity options and Diversity Method 1 are further flawed by the use of ALF. As such WACMs 3, 17, 24 and 31 do not better facilitate ACOs A and B (as well as the Original and WACMs 2, 7, 9, 14, 16, 21, 23, 28 and 30). A major advantage of Diversity Method 3 is that it does not employ an ALF sharing factor, but rather a Zonal Sharing Factor (ZSF), ensuring that TNUoS continues to represent a fixed cost of generation. This will avoid impacting the efficiency of the wholesale market. Method 3 also represents sharing on the transmission system in a fairly realistic manner (as discussed above). However, these benefits are tempered by the additional complexity associated with this option (although noting it is at least no more complex than the other options being considered). As such, we believe that Diversity 3 has the potential to better meet the ACOs, although we consider that further evidence, particularly reassurance of the robustness of the modelling, is needed to come to a final view on this option. 6. <u>Year Round - Hybrid</u> The Hybrid approach does not in any way reduce the complexities associated with the ALF approach (as detailed above). It will also establish further complexity in the administration of TNUoS charging (including administering User Forecasts), with no obvious benefit apparent. We therefore do not consider this to be a viable option. As such, we do not believe WACMs 1, 5, 6, 12, 19, 22, 26, 33 and 40 better facilitate ACOs A and B. **Parallel HVDC and Islands** We first note that the requirement to reflect HVDC links in the TNUoS charging methodology is imminent. As such changes would be required to the current ICRP methodology regardless of Project Transmit/CMP213. We consider that the incremental power flow calculation, which applies to all options, is sensible. We also consider that where Island circuits are comprised of HVDC technology, the charging methodology should be consistent with that for HVDC transmission circuits paralleling the AC transmission network, to ensure that competition is not distorted. We also agree that specific expansion factors are appropriate (which applies to all options) considering the relative uniqueness of this type of transmission equipment. As such, the only major differences between the options with regards to the treatment of HVDC technology, is in how they treat converter station costs. We provide our views on these different options below.

	7. Specific Expansion Factor, 100% Converter Station Cost + 100% Cable cost We believe it has been sufficiently demonstrated that a proportion of HVDC converter station costs are equivalent to the costs associated with onshore AC substations, i.e. they exhibit similar characteristics as those elements of the AC system which are not included in the locational element of TNUoS. Therefore we believe it is correct to treat these costs in an equivalent manner to ensure competition is not distorted. This option (100% of Converter Station costs in the locational element of the tariff) fails to treat similar costs equivalently. As such we do not believe this option better facilitates ACOs A and B. Therefore the Original and WACMs 1, 2, 3, 4, 5 and 6 do not better facilitate the ACOs. All the options discussed below try to ensure equivalent treatment of HVDC Converter Station Costs. The question is what proportion of these costs are equivalent and how should the proportion be calculated and applied. 8. Specific Expansion Factor, generic 40% Converter Station Cost + 100% Cable cost (AC substation + QB) 9. Specific Expansion Factor, generic 50% Converter Station Cost + 100% Cable cost (AC substation) 10. Specific Expansion Factor, generic 30% Converter Station Cost + 100% Cable cost (AC substation + STATCOM) We do not believe that the three generic options, requiring various percentage reductions in converter station costs from the locational element, would be sufficiently cost reflective. This is because there is insufficient information on which to create a generic forward looking factor, for HVDC converter station costs, and that the costs of different HVDC converter stations are sufficiently different to justify a specific treatment of each one. Also, as this is the rationale for specific recovery of costs in offshore transmission charging, this will ensure equal treatment of Users. There are likely to be relatively more offshore networks than bootstraps and links to islands, and therefore we cannot envisage how collecting information for HVDC links would be any more onerous so as to justify a different approach. Overall, generic approaches are likely to either under or over reflect the actual proportion of AC costs associated with HVDC converter stations. As such, we consider a generic approach an arbitrary means of attributing transmission costs. With regards to the postulated benefits of QB and STATCOM, we consider these benefits are likely to be somewhat nebulous, difficult to quantify and, whilst they may result in lower operational costs, they are not relevant to the incremental cost of transmission capacity upon which TNUoS charges are based

	and expansion factors are calculated. As such WACMs 7, 9, 12, 14, 16, 17, 18, 19, 28, 30, 31, 32, 33 and 40 do not better facilitate ACOs A and B. 11. <u>Specific Expansion Factor, specific x% Converter Station Cost + 100% Cable cost (AC substation)</u> Having noted the problems associated with the Original and generic approaches above, we believe that the specific Converter Station Cost option would best mitigate these disadvantages by ensuring equivalent treatment of similar costs and minimising distortions to competition. **Best potential option** Considering the different options above, we believe that WACM 25 has the best potential to better facilitate the relevant ACOs. It better treats HVDC costs relative to the baseline (noting that HVDC treatment would need to be defined anyway) and develops a plausible method of incorporating sharing in to the charging methodology. It also does not use a form of ALF and thus avoids creating further complexity in the wholesale market (as discussed above). However, it is more complex than the baseline (at least the sharing element) and may therefore be expected to drive greater unpredictability in future charges. As such we believe that Ofgem should further investigate this option to determine whether benefits outweigh costs as part of their Regulatory Impact Assessment (RIA). An alternative option may be to retain the current ICRP methodology and only make the necessary changes to ensure that HVDC charging principles are incorporated in to the methodology, i.e. adopt a specific expansion factor, specific x% Converter Station Cost and 100% Cable cost. We note that, due to the structure of CMP213, a new modification would be required to enable the implementation of this option. **The Original and WACMs – views against the ACOs** We summarise our views on the Original and all the WACMs with reference to the ACOs (specifically A and B) in an annex at the end of this consultation response.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	The Workgroup has not codified a proposed implementation approach, but has provided a number of options for Ofgem to consider, including relevant pros and cons. Of the options presented, we prefer implementation of the new methodology from 1 April 2015 (assuming an Authority decision by Autumn 2013). This will allow parties to efficiently take account of tariff changes in their business plans and avoid

	inefficient exit costs. This lead time is, importantly, in keeping with CM192 User Commitment arrangements. The User Commitment interaction is that during the normal course of events a User with generation assets must provide notice (to reduce their TEC) to the SO at least one year and five working days prior to the start of the charging year in question, in order to avoid paying a cancellation charge based on system investment costs. A decision made within this window forces the User to incur a cost which they cannot efficiently manage. In order to be consistent with these arrangements, a 1 April 2014 implementation date is unworkable. Moreover, preapproval work on tariffs is insufficient to allow implementation for 2014/15. If an earlier implementation date (i.e. before 1 April 2015) is directed, we believe there will be a requirement to introduce some form of transitional measures, e.g. TEC reduction options and/or grandfathering. This represents a sub-optimal outcome and renders the implementation of CMP192 pointless. Such transitional arrangements could also be viewed as being anti-competitive, susceptible to gaming and costly to administer. Conversely an implementation date of 1 April 2015 would not require any transition arrangements. Additionally, we note that midyear tariff changes are administratively burdensome and risk increasing tariff volatility. As such they are best avoided. Transmission tariff changes should occur at the start of the charging year.
Do you have any other comments?	We believe that the following issues (noting that the issues identified below are by no means exhaustive) will need to be addressed to ensure that the modelling outcomes are robust and provide a reasonable evidence base to distinguish between the merits of the different charging options. **Sensitivity analysis** A number of the underlying assumptions made as part of the modelling exercise should be subject to sensitivity analysis to ensure outcomes are consistent and robust subject to a number of different macro-economic scenarios. Assumptions which should be subject to sensitivity analysis include: • Demand – the current modelled assumptions on demand assume aggressive energy efficiency improvements. Weaker energy efficiency performance is likely to require greater generation capacity, which is likely to materially impact the modelled outcomes. • Commodity prices – the modelled assumptions assume commodity prices ‘flatten’ post 2018 and that significant oil and gas price decoupling occurs. There is a great amount of commodity price uncertainty and different commodity price assumptions are likely to materially impact the modelled outcomes. In particular, different assumptions are likely to have a material

	impact on the levy control framework restriction. We note that the restriction is narrowly met in all scenarios, which would suggest that alternative assumptions may impact this key determinant of low carbon generation development. **Stage 2 'goal seek bias'** All the options modelled meet the policy targets as determined by the stage 2 parameters. However, it is difficult to evaluate whether the means by which the targets are reached are a realistic reflection of how the market is likely to behave without further understanding the modelling inputs and effects. Further in-depth analysis of how policy goals are met, and whether these are reasonable, should be undertaken. **The Status Quo/Diversity 3 and offshore wind** There is far greater penetration of renewables between 2013 and 2018 under the Status Quo and Diversity 3 options. This is primarily driven by far greater increases in the development of offshore wind capacity, which in turn is driven by relatively large profits accruing to offshore wind developers. These profits are likely to be a determined by relative levels of TNUoS charges and/or CfD payments. This resultant renewables development seems counterintuitive when considering the charging principles associated with the different charging options, i.e. models that employ an ALF scaling factor and a two part tariff are likely to favour intermittent generation relative to other forms of generation. However, the Status Quo and Diversity 3 options do not employ these methods. Without having full view of the modelling figures, it is very difficult to evaluate what causes the increase in offshore wind capacity. Understanding this effect should be a priority for Ofgem. Nevertheless, we suspect that the model might not be accurately calculating TNUoS charges for offshore wind generators. This might also explain why the CfD strike prices for offshore wind are much lower under the Status Quo and Diversity 3 options relative to the other charging options. **Transmission costs and the 50% HVDC converter costs option** Transmission costs under all the options are very similar except for the 50% HVDC converter costs option. The divergence in 2017 can be attributed to bringing forward the Caithness HVDC project by one year. However, it is very difficult to understand why this project has been brought forward. The model outputs and inputs are very similar for both the 50% HVDC converter costs option and the Original. Ofgem will need to investigate what is the plausible driver for the difference in transmission costs. **Original option 2024** As already noted by the CUSC Panel, there would appear to be

	an error with the Original TNUoS tariffs in 2024. This should be investigated and corrected if necessary. Other potential discrepancies include: • Year Round tariffs for Diversity 3 are reported to be 0 across the different years and zones. On the other hand, values are reported for Peak tariffs. We suspect that the two sets of figures have been accidentally swapped; • Cumulative generation addition versus status quo show incorrect formulae in the New Build by Zone tab; • Residual component of charging in Diversity 3 is not included. As market participants are unable to follow the inputs through the model and out of the other side, National Grid should investigate the above issues and provide comment on whether the discrepancies are the result of modelling error or they are errors of a presentational nature.

Annex - The Original and WACMs – views against the ACOs

<u>Original</u>

The Original does not better facilitate the ACOs because it does not reflect plant diversity, uses an ALF historic approach and allocates 100% of HVDC Converter Costs to the locational element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

<u>WACM 1</u>

WACM 1 does not better facilitate the ACOs because it does not reflect plant diversity, uses a Hybrid ALF approach and allocates 100% of HVDC Converter Costs to the locational element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

<u>WACM 2</u>

WACM 2 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Historic ALF approach and allocates 100% of HVDC Converter Costs to the locational element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

<u>WACM 3</u>

WACM 3 does not better facilitate the ACOs because it uses a Historic ALF approach and allocates 100% of HVDC Converter Costs to the locational element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

<u>WACM 4</u>

WACM 4 does not better facilitate the ACOs because it allocates 100% of HVDC Converter Costs to the locational element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 5

WACM 5 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Hybrid ALF approach and allocates 100% of HVDC Converter Costs to the locational element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 6

WACM 6 does not better facilitate the ACOs because it uses a Hybrid ALF approach and allocates 100% of HVDC Converter Costs to the locational element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 7

WACM 7 does not better facilitate the ACOs because it does not reflect plant diversity, uses a Historic ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 9

WACM 9 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Historic ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 12

WACM 12 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Hybrid ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 14

WACM 14 does not better facilitate the ACOs because it does not reflect plant diversity, uses a Historic ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 16

WACM 16 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Historic ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 17

WACM 17 does not better facilitate the ACOs because it uses a Historic ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 18

WACM 18 does not better facilitate the ACOs because it allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 19

WACM 19 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Hybrid ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 21

WACM 21 does not better facilitate the ACOs because it does not reflect plant diversity and uses a Historic ALF approach. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 22

WACM 22 does not better facilitate the ACOs because it does not reflect plant diversity and uses a Hybrid ALF approach. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 23

WACM 23 does not better facilitate the ACOs because it does not accurately reflect plant diversity and uses a Historic ALF approach. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 24

WACM 24 does not better facilitate the ACOs because it uses a Historic ALF approach. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 25

WACM 25 has the potential to better facilitate the ACOs. It better treats HVDC costs relative to the baseline (noting that HVDC treatment would need to be defined anyway) and develops a plausible method of incorporating sharing in to the charging methodology. It also does not use a form of ALF and thus avoids creating further complexity in the wholesale market. However, it is more complex than the baseline (at least the sharing element) and may therefore be expected to drive greater unpredictability in future charges. As such we believe that Ofgem should further investigate this option to determine whether the potential benefits outweigh the costs as part of their RIA.

WACM 26

WACM 26 does not better facilitate the ACOs because it does not accurately reflect plant diversity and uses a Hybrid ALF approach. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 28

WACM 28 does not better facilitate the ACOs because it does not reflect plant diversity, uses a Historic ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 30

WACM 30 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Historic ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 31

WACM 31 does not better facilitate the ACOs because it uses a Historic ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 32

WACM 32 does not better facilitate the ACOs because it allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 33

WACM 33 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Hybrid ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

WACM 40

WACM 40 does not better facilitate the ACOs because it does not accurately reflect plant diversity, uses a Hybrid ALF approach and allocates a generic percentage of HVDC Converter Costs to the residual element. As such the methodology is not more cost reflective and will not better facilitate efficient competition.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

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Respondent:	Paul Mott
Company Name:	EDF Energy
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	Summary Overall we consider that the original is marginally better than the baseline. However the Original does have some deficiencies particularly around the use of load factor to determine the extent of sharing. The views set out below explain our reasoning and translate into a preference for WACM 25 as best, with WACM 24 the second-best. WACM 25 features diversity method 3, a specific cost reduction from the expansion factor for parallel HVDC links equal to the cost element that equates to an AC substation, and a specific cost reduction from the expansion factor for island HVDC links equal to the cost element that equates to an AC substation. WACM 24 features diversity method 2, annual load factor as per CMP213 original (5 year basis, no challenges), a specific cost reduction from the expansion factor for parallel HVDC links equal to the cost element that equates to an AC substation, and a specific cost reduction from the expansion factor for island HVDC links equal to the cost element that equates to an AC substation. CMP213 Original There are elements of the CMP213 original change proposal and all of its variants, that better facilitate CUSC charging applicable objective (c) (developments in the TOs' transmission businesses) and, slightly, (b) (cost-reflectivity). This is because the baseline charging arrangements have not been modified to

	assign an impedance to an HVDC circuit (whether island link or bootstrap) in the DC load flow model used at the core of ICRP. The construction of the first such HVDC circuit is now underway, so this comprises a development in the TOs' transmission business. The assignation of this impedance is not itself challenging or controversial, as a suitable impedance can be defined, but is necessary as an HVDC circuit does not readily map to any given impedance. CMP213 and all its variants, or WACMs, identify a reasonable impedance for such circuits (the variants do not vary in this respect). Another aspect of CMP213 and its variants that better facilitates CUSC charging applicable objective (b) (cost-reflectivity), is that it addresses the potential, in today's TNUoS charge calculation method (baseline), for over-charging of the local circuits that island links will comprise. The over-charging would arise, under baseline, where these island links feature no redundancy. The baseline charging method would inadvertently over-charge generators based on islands because a security factor of 1.8 is applied, as though the island connection benefitted from redundancy, even where the island link lacks redundancy. CMP213 and all its variants, or WACMs, resolve this in the same manner – by diluting the "expansion factor", or relative cost, of the island link by 1/1.8 (i.e. multiply the factor by 0.555…), where the island link is non-redundant. Therefore, there are elements of CMP213 and all its variants, or WACMs, which better facilitate CUSC charging objectives (c) and (b), for the reasons set out above. On the other hand, offsetting this, there are elements of CMP213 original (and its variants with the same load factor dilution of the year round charge), that facilitate CUSC charging objectives (a) and (b), worse than baseline. This is because of the load factor dilution aspect of CMP213 Original : we consider that the use of location-independent load factor for this purpose is a crude and inaccurate approach so that it is deleterious to charging objectives a and b. However, the benefit as shown in our opening paragraph against objective (c) is sufficient that the Original is just better than baseline overall. The Load factor/congestion cost relationship proposed is too simplistic. We do not believe there is a confirmed link between each generator's load factor and transmission investment decisions arising from that generator. Bid price and diversity are also important. The use of location-independent load factor as the year-round charge dilutant is not cost-reflective, and is not reflective of the reality of how access is shared by classes of generators behind different boundaries. Specifically, the Original and these variants will, in zones where low load factor generation of only one type is present, significantly underestimate the incremental cost of transmission to service

	low load factor generation there. The transmission planning investment decisions in these areas will clearly not be load-factor driven as the cost of constraining off low carbon lowish load factor generation will be dearer, due to its bid price characteristic. The reality of SQSS GSR009, which lies at the heart of the CMP213 origination philosophy, is that it entails the striking by NG's transmission planners of a balance between BSUOS charges and transmission investments. The Original and these variants do not reflect this well; they fail to reflect the higher cost of constraining off low load factor plant with costly bid prices that are accepted. The Original and these variants do not reflect the benefits of higher load factor, carboniferous, plant in areas dominated by intermittent plant types. Overall, we consider that the Original and these variants are just better than baseline taken across the three charging objectives in span. <u>Diversity variants 1, 2 and 3</u> There are also elements of all the CMP213 variants featuring diversity method 1, that facilitate CUSC charging objectives (a) (competition in generation and supply) and (b), slightly worse than baseline. This is because all of the CMP213 variants featuring diversity method 1, will charge most of the year-round incremental MWkm on load factor times TEC in areas featuring mainly carbon generation types. Intuitively, we would expect real sharing to maximise in areas with a mix of carbon and low-carbon generation behind a boundary; where either type dominates the mix behind a boundary, sharing does not appear likely to be a real phenomenon, and we would not expect there to be any load factor dilution of the year round charge. Moreover, we would not expect load factor dilution of the year round charge to exceed 50%, even when the mix of carbon and low carbon behind a boundary is even. A significant proportion of the capacity of each new generator, of either type, will still need to be serviced in terms of new transmission. Overall, we consider that all the CMP213 variants featuring diversity method 1 are worse than baseline taken across the three charging objectives in span. The CMP213 variants featuring diversity methods 2 and 3 do not have the drawbacks of the variants of the original and the variants of method 1. They reflect what is intuitively obvious : that one would expect real sharing to maximise in areas with a mix of carbon and low-carbon generation behind a boundary; where either type dominates the mix behind a boundary, sharing does not appear likely to be a real phenomenon in transmission

	planning, in relation to new generator connections. Moreover, they feature maximum charge dilution of 0.5 times TEC, where there is a 50/50 mix of generation types behind a boundary, reflecting what seems intuitively correct. There will not be 100% sharing, even for such a "perfect" mix; a significant proportion of the capacity of each new generator, of either type, will still need to be serviced in terms of new transmission and therefore a 50% limit provides a simple approximation for this. Sharing arises from the combination of generation behind a boundary but not clearly from each plant's own load factor. There is some inherent merit in simplicity, all other things being equal. Method 3 is simple in that it features a two-part tariff, and in that there is no need to take account of each plant's load factor. These load factors for coal plant are inevitably likely to be in decline over time, although there was a recent uplift that would not have been forecastable. Gas plant load factors may decline or may not, dependent on factors that are very hard to forecast, but which boil down to the relative cost of delivered gas in GB compared to that of coal, after making allowance for carbon pricing and relative efficiencies. There seem to be some hazards in an approach that relies on specific plant's load factors. This is another reason why we support method 3 as it removes this inherent issue with the use of ALF. Moreover, the "hybrid" approach has hazards of its own, since plants choosing under that approach to challenge the load factor calculated for it within CMP213, will face a severe penalty if its load factor out-turns at a different level to the forecast it chose to submit. A result is that these plants would have a strong incentive to ensure that their load factor matches their forecast, which would warp their operation during the last month or two of the TEC charging year. It is undesirable that the TNUoS charging method should warp commercial operation in this manner. It should not pass without comment, that method 3 abandons the peak security charge element. Experience in operating SQSS GSR009, in planning alterations to the transmission system, shows that 80% of circuits are allocated to the year round study, and that the peak security charge element will be relatively small compared to the year round element. For this reason the abandonment of the peak security charge element in method 3 has limited effect on cost-reflectivity, or on preventing the TNUoS charge calculation from mimicking precisely the current SQSS approach to new circuit planning. The gain in simplicity through its abandonment, in variants of CMP213 based on WACM 3,

	would seem to marginally exceed the small loss in potential cost-reflectivity. Overall, taking all of the considerations above into account, we consider that both the variants based on method 2 and the variants based on method 3 do better facilitate the charging CUSC objectives taken in span than baseline, but that the variants based on method 3, do so to the greatest extent. <u>HVDC and Islands</u> Moving on from the treatment of diversity/sharing to other aspects of CMP213, we have given careful consideration to the arguments around whether some of the HVDC converter costs, for both island links and HVDC offshore ("bootstrap") links, should be removed from the relevant expansion factor, and hence from the locational charge elements. We do accept that in many cases an AC substation would have been constructed at the location of the converter, and that AC substation costs are not included in the DCLF model. Therefore, we accept that these costs should be removed from the converter cost in calculating the expansion factor for each HVDC island link or bootstrap. This will represent a slight over-compensation, since in some cases no AC substation would have been constructed had an onshore AC connection been used in place of a bootstrap, but it is simplest to adopt a rule that this cost element be removed. As to whether the substation-equivalent costs for each HVDC converter should be calculated on a specific basis or from a generic basis: ideally we would prefer the specific approach. The generic proportions options are based on one-off evidence, which may not be representative going forward. We do note NG's comments that this may not be practical, as it is concerned about complexity. If in specific instances there were real difficulties for NG in accessing the necessary information, perhaps because the TO purchase contract for the cable was on a turnkey basis, then the default generic information could be used as a substitute in this case. We do not consider that the case for the further removal from converter costs, of cost elements equivalent to the costs of ac quad boosters or static compensation, is made. It is not well evidenced that these ac circuit elements would have been needed or constructed in those areas, had an ac connection been made.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We note that CMP213 allows for an Ofgem decision on the implementation date. It has no transitional or grandfathering arrangements included. We see no reason to call for transitional or grandfathering arrangements, but do need good notice of what the new tariffs will be. The modelling results of CMP213 are so deficient that, if a decision were made today by Ofgem without the release of better modelling, suppliers and generators would have little idea what the tariffs would be when CMP213 came in. We have some views on choice of implementation date which we set out below. The uncertainty around CMP213 is unsettling, and it would be helpful for generation investment if the matter could be resolved in terms of a determination of the outcome. This must give visibility of what the tariffs will be going forward, in numerical terms, to reasonable accuracy with at *least* 12 months' notice. The modelled tariffs that were released just before the working group's vote show evidence of gross errors in the stage 2 (15th March) modelling. The modelling needs to be re-conducted in an error-free manner. It is not satisfactory to say that, for instance, the gross error that is evident across all generation tariffs (all being strongly negative, for all zones, which lacks any credibility) in the year 2024 in the stage 2 modelled CMP213 original tariffs, should be simply "discounted" because, loosely speaking, NG says that something must have gone wrong, and that it will identify and fix it later. The other stage 2 modelling results are all based on the same modelling approach, and just because they do not show such a gross and evident error, one cannot assume they are not also materially affected by it; indeed it would seem highly likely that they must be. It is quite impossible to have any confidence in the stage 2 modelling results as they are. The stage 1 (15th February) modelling results featured no demand tariffs at all, related only to 2015, and as to generation tariffs, the constituent elements were never published; neither were any baseline results. What was published in that "stage 1" modelling for 2015/16 only, were the net effective tariffs for a 70% load factor conventional plant and a 30% load factor intermittent plant, for each zone; since the 30% load factor intermittent tariff included, for original and methods 1 and 2, an undisclosed peak security tariff element, it was not possible to accurately interpolate to the effective tariff for plant of other load factors – there was insufficient information (one would have needed the residual, year-round and peak security tariff elements, and the shared and not-shared proportions of the year-round element for methods 1, 2, and 3 by zone – this

	information was with-held, and has never been published). It would be markedly unsatisfactory if Ofgem were to opine and pass a variant of CMP213 in the autumn, for implementation in April 2014, without any modelled tariff numbers for demand at all that one could rely on, nor for generation. This would leave supply, in particular, and also generation businesses, waiting until perhaps January the 6th 2014, before they knew tariffs that would have effect from as soon as 1st April 2014. This is inefficient; risk would result on the Supply side, If good tariff modelling allowing fairly accurate business planning isn't available before 1st September this year, then we suggest that implementation should be in April 2015. We do not support a mid-year (non-April-1st) implementation.
Do you have any other comments?	No

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Respondent:	*Michelle Dixon*
Company Name:	*Eggborough Power Limited*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	Eggborough recognises that the group has done a lot of work on this modification. However, on balance, we do not feel that the modification or its alternates achieves a robust way to charge for use of the system at a time when we are facing significant change in the way the market operates. Our view is formed on the basis of the work in the report, as we have not attended the group and benefitted from hearing the debate. We have, however, found that the limited analysis on participant impacts make it difficult to judge what the longer term impacts of the proposals will be. We appreciate that this is in part due to the governance arrangements, but more robust analysis of the original and couple of alternatives would allow further consideration and we assume Ofgem will undertake some form of Impact Assessment. The idea of sharing capacity is to be welcomed, but we are not convinced that intermittent plant (as defined) is necessarily sharing more than others. It seems entirely possible that the peak flow on one circuit may be entirely as a result of intermittent generation as that is the predominant generation in that region. While the system may be designed on the basis that the intermittent plant does not use peak capacity that does not mean it does not use it. What seems more relevant is that at present some regions of the system have more intermittent plant sharing capacity or being constrained off. Looking into the future, there is nothing to say that “intermittent”

	plant will run significantly more than older, conventional plant. That plant may also not run at "peaks", but at times of low output from intermittent plant. The concept of the allocating non-shared costs would seem to be more cost reflective than assuming that there is simply no use of certain peak assets. However, this clearly has some additional complexities. It is difficult to determine from the consultation what the impacts of different types of sharing could be, but Eggborough is concerned that the signals sent risk weakening location signals to the detriment of the economic development of the network as a whole. The proposal is not obviously "cost reflective" nor is it likely to result in the most efficient outcome for the transmission business. Instead the proposals feel like a means to lower transmission charges to some types of generators, which may be more efficiently achieved by locational FITs, or some other direct support mechanism. Were the modification to be approved, Eggborough would have a preference for a hybrid version where the generators can at least set their own load factors. In the case of coal plant, the previous two years have seen high load factors, but it would be reasonable to assume that running hours will reduce were relative fuel prices, carbon costs, etc. to alter. However, as thermal plant typically responds to short term market signals, there should be some greater tolerance around the load factor, so that there is not a risk of a big step up in energy prices. For example, if coal price suddenly reduced in say November, then low pressure reduced wind output and thermal plant is suddenly called on to run and must factor "penalty charges" into energy prices, then short term prices could increase. Any charging structure for monopoly assets that has the potential to create energy price volatility seems less than perfect. The market model that looked at load factors must have made assumptions about plant economics that we expect will alter significantly over time. We assume that constraint costs will alter as investment in transmission catches up with the demands of the connect and mange regime. Looking back at constraint costs and load factors in a changing market suggests that the chance of the model being right is minimal. The relationship described may not therefore be as robust as the proposer suggests. On the HVDC work, we are concerned that converter costs are not removed because if they exist to support the link then the users of those assets should pay the associated costs. Where it

	could be demonstrated that some of these costs would have been incurred in the absence of the HVDC links then there may be a case for removing some of those costs, but this would have to be done on the basis of a clear cost comparison. It also seems inconsistent with the way the OFTO regime operates, without any clear explanation as to why the two are different. For the Scottish Islands, Eggborough again feels that the costs should be allocated to the system user, while recognising the impact this has the economics of generation connected there. However, we would still prefer to see a more cost reflective charging and a direct subsidy to the generators so that the development of generation on the Islands is explicitly supported, making the true costs of these plants clearer. On balance we do not feel that the modification or its alternates are better than the baseline, though we appreciate what the proposer was trying to achieve. The changes would remove the locational signals and reduce cost reflectivity, which will not be beneficial to competition. It could create less economic investment signals and seems to unduly discriminate against certain plant types and locations.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	EPL believes that a longer implementation timetable would better allow generators to adapt to the changes. EPL would therefore support implementation in April 2015.
Do you have any other comments?	*No*

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Respondent:	*Neil Kermode, Managing Director, EMEC, Orkney.* *Tel 01856 852061* *Neil.kermode@emec.org.uk*
Company Name:	*European Marine Energy Centre*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	**The Original and most of the WACMs (with the possible exception of the Diversity 3 option) are better than the Baseline in that they:** **Facilitate better the Competition** between generators including keeping costs down due to fewer barriers to new entrants offering lower cost/lower volatility low carbon fuel sources – thus helping to control consumer bills going forward. The CMP 213 options with sharing under the ALF model and including relief from AC analogue fixed (Residual) elements – HVDC Converter Stations – for parallel and Island Links are better in terms of advancing competition in that, whilst signalling higher TNUoS than less peripheral parts of the Transmission Network, the overall burden of Locational Charges – which add to costs of most generators – offer less volatility and lower charges than the Baseline. All the diversity options – in particular options 2 and 3 – are likely to add a level of volatility in charges for intermittent generators in the North and the Scottish Islands. This is because the closure or reduction in TEC of conventional (carbon) generation in a zone or neighbouring zone would impact immediately on low carbon generators by increase their TNUoS. The consequent volatility and cost increases would tend to undermine competition. **Offer better Cost Reflectivity** – in that where network is shared it can be reflected in Locational TNUoS charging whilst

	maintaining price differentials (locational signals). The sharing model based on Annual Load Factor (ALF) appears to balance absolute cost reflectivity with simplicity and transparency, whilst Diversity 2 and 3 seem to add a level of complexity and the concentration on constraint costs across boundaries without modelling any counter correlation between intermittent (low carbon) generation. **Take account of developments in Transmission System (TO's Businesses) –** the Transmission Network is facing a period of change with important reinforcements, increasingly reliant on offshore HVDC links running in parallel to the onshore network and thereby reducing constraints. Other areas of high energy resources, such as the Scottish Islands off the NW and N coasts of Scotland, are being connected with 'new' technology (not currently included as Expansion Factors in the current TNUoS charging methodology) using AC subsea cables (Orkney) or HVDC subsea cables (Shetland and Western Isles). The Baseline (Status Quo) is not fit for purpose in that the methodology, as it stands, does not offer a solution to the development of the Transmission network and thus the necessary changes in Transmission Owner's Business in that it does not address Expansion Factors for these new and necessary technologies. The Original and the WACMs seek to address this by looking at system planning based more on Cost Benefit Analysis where sharing is a factor. Those CMP213 options which look at bringing HVDC converter stations into line with the existing methodology concerning fixed parts of the network (such existing AC substation and voltage regulation) are more likely to reflect developments in the Transmission System. **Further arguments supporting an option as 'Best' against CUSC objectives.** Although the Original and most of the WACMs are, in our view, better than the Baseline (status Quo) for the reasons we have explained above in relation to the Applicable CUSC objectives – there are wide differences between the options (WACMs) developed by the Workgroup. We note that the Workgroup was not able to arrive at a consensus on all elements of the proposal – but nevertheless some of the elements were widely supported of these we note: **Counter Correlation Factor (CCF)** for local/radial links (in the cases highlighted these were Scottish Island links). This element is dealt with in WG Report vol 1 4.105 – 4.113 p49 – p51 and in more detail WG Report Vol 2 4.265 – 4.345 p66 – p80. The work done by Heriot Watt (ICIT) is robust and has been reviewed extensively by modellers at National Grid, who were provided with source data and algorithms used by the author of the work at Heriot Watt (ICIT). The work indicates that significant degrees

	of sharing are likely to be achieved by intermittent generators of different types exporting along a single link. The provision of the links could be made on a more cost effective basis if planned with CCF in mind from the outset – and certainly against he contracted background of connections. Furthermore, once built, any link could be used to connect more generation –showing a degree of counter-correlation – than originally planned, or subsequent links could be built at reduced cost or maybe even avoided with savings to all users. We note that CCF was incorporated by the Proposer into the Original and into all WACMs by proposers of those variants. **HVDC - removal of some elements of Converter Station costs from the Locational elements of TNUoS for both Parallel links ('Bootstraps') and Island links.** – Significant evidence was presented to the Workgroup from a number of sources to support the concept of removal of certain elements of the costs of the Converter Stations included in the HVDC technology. Elements which were analogues of AC substations or voltage regulation and which would be classed as fixed rather than locational for the purposes of standard onshore links were identified. There was strong support for at least 50% reduction in converter station costs included in the Locational elements of TNUoS (Wider in the case of Parallel links and Local Circuit charge in the case of Island Links) via the Expansion Factor. There was also significant support for the inclusion of HVDC Converter Station analogues to AC Quadrature Boosters for Parallel links and STATCOMS (network voltage regulation) for Island links. This would translate to an additional reduction of 10% and 20% respectively. There was some support for a specific case- by –case reduction based on National Grid receiving sufficiently detailed information from technology suppliers. There is, in our view, significant weakness in this proposal as such information is often withheld for reasons of commercial confidentiality and its absence would likely lead to initial delays in advising TNUoS followed by an estimate of 50% reduction anyway. Many WACMs (20 of the 26 WACMs), though not the Original, support at least 50% reduction of Converter Station costs which indicated a strong level of consensus within the Workgroup. Our view is that the higher levels of reduction (60% for Parallel and 70% for Island links) are justified by the evidence presented to the Workgroup. **Security Factor (SF) for single Island links –** we note that the proposal to use a Security Factor of 1.0 (rather than 1.8) in the calculation of single circuit Island links where they may be considered 'Wider' (in those options including Diversity) was accepted by the Workgroup and is included in the Original and all WACMs. In the Original and WACMs incorporating Annual

Load Factor (ALF) single Island circuits will always be 'Local' where SF is already defined as 1.0.

New MITS (charging only) definition for radial links (such as Islands) – counted as 'Local' where interruption of the link would interrupt export to the National Electricity Transmission System (NETS). – This change received support from WG members representing generators in the 3 Scottish Island groups and was proposed by National Grid in order to remove a possible anomaly if ALF (in the Original or WACMs 1,7,14, 21, 22, 28) was adopted. This would mean that – at least in the first round of planned reinforcements to the Islands – sharing could only be considered under CCF and that reductions to Locational TNUoS due to Load Factor alone would not take place.

Sharing – ALF or Diversity?

There was a split in the Workgroup when considering the method of sharing to be applied (and in a few cases no form of sharing was supported) between support for ALF on the one hand and Diversity on the other. We believe that sharing based on a proxy of actual Annual Load Factor per generator on the 'Wider' network is simpler, more transparent and less prone to short term volatility than the Diversity options. Whilst Diversity offers, potentially, more cost reflectivity in peripheral areas with extensive build out of intermittent Low Carbon generation and lower volumes of conventional (Carbon) it is done at the expense of simplicity and to an extent transparency and volatility – since the actions of other users, particularly high capacity carbon based generators, reducing TEC or closing could lead to immediate and significant increase in TNUoS.
Diversity is based almost exclusively on predicted constraint costs across boundaries and rules out counter correlation as a sharing factor between intermittent (Low Carbon) generators in generation zones. This matter was discussed in the Workgroup (Report Vol 1 4.57 – 4.60 p41) – pointing out the work done by ICIT (Island sharing) showed that Intermittent generators can share and that this should be considered in the Wider network as –for instance – wind generators placed geographically widely spaced from others in large generation zones could experience differing onset, duration and intensity of wind and would partly counter-correlate and thus share the system. National Grid suggested that Diversity could be improved by inclusion of such sharing factors if evidence was later offered to the SQSS Review Panel for consideration (4.58).

Diversity 1 allows 100% of sharing (ALF) across boundaries where there is at least 50% of conventional (Carbon) generation

	with Megawatt Kilometres excluded from ALF in those parts of the system as the proportion of Low Carbon increases from 50% to 100%. This serves to increase TNUoS in peripheral zones rich in renewable energy resources and could act as a barrier to renewables based projects in those areas. Diversity 2 whilst based (as Diversity 1) on the dual background (Peak and Year-Round) assumes sharing even on zones where there is a 50/50 mix of Carbon to Low Carbon generation is capped at 50% (rather than 100% in Diversity 1) of ALF tailing off in both 'directions' when the mix departs from this ideal (both in more Carbon or more Low Carbon directions). In our view the case for the 50% in not justified and seems somewhat arbitrary. The effect of Diversity 2 is the application of even sharper signals in the North of the network and the Islands than Diversity 1 and potentially more volatility with greater 'penalisation' of Low Carbon generation as Carbon generation reduces in these areas. Diversity 3, alone, departs form the Dual Background approach common to ALF and Diversity 1 and 2. It uses the Year Round background only, but in doing so loses the link between those generators who time output at peak and the provision of the Network to accommodate these flows. This method uses the arbitrary 50% cap on sharing (in common with Diversity 2) and likewise reduces in both directions (both in terms of higher proportion of either: Carbon/Low Carbon or Low Carbon/Carbon. Its effects on peripheral areas of high renewable energy resources is even more severe than Diversity 2 and due to the level of potential volatility in TNUoS may be worse than the baseline – because although Locational TNUoS may be slightly lower than the Status Quo the increased uncertainty would seem to cancel out any benefit. **Modelling carried out by National Grid on Workgroup outputs (WG Report Vol 2 p230 – p265).** A set of scenarios bases on some of the CMP213 outputs (Original and some WACMS) are modelled in WG report Volume 2 **Significant** – comparisons of **strike prices** needed to maintain expected low carbon targets according to various CMP213 outputs (e.g. ALF and Diversity options) p245-246. The strike prices have been adjusted so that the outputs for MW of Low Carbon generation are within UK an EU targets for electricity - thus as costs bear down on the development of renewables in areas like N Scotland and the Islands, as time progresses – under the Status Quo or Diversity options - the strike price is adjusted upwards in this second tier modelling. For instance the Strike Price for Original plus 50% reduction on HVDC Converters in 2018 – 2020 is £94 (£/MWhr) whilst for Diversity 1 it is £98,

	Diversity 2 £98 and Diversity 3 £97. In 2021 – 2013 the estimates are, respectively: £92, £97, £97, £96. This is picked up in the change in Consumer Bills (relative to Status Quo) –as the support in the CfD is reflected in consumer's bills. **Change in average Consumer Bills from Status Quo - p243** It is significant that the plot for the Original + 50% Converters (Lower TNUoS) (red line) compares favourably against all the options and in particular the Diversity options (which have the higher levels of TNUoS in the Highlands and Islands area). We consider that ALF plus reductions for HVDC converters are most in accord with the aims of Project TransmiT (ref Electricity transmission charging arrangements: Significant Code Review conclusions 4 May 2012 1.1 p6) *"The aim of Project TransmiT is to ensure that we have in place arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers."* The beneficial impact on Consumer Bills going forward, and the encouragement to low carbon energy generation in areas where it is most available plus development of high quality and efficient transmission network through HVDC links to the Scottish Islands and links Parallel to the existing AC network is significant. Overall, and based on the reasons above, we believe that all Options incorporating ALF, Including the Original, are better than the Baseline and the Diversity options. We are confident in this assertion since the main anomaly, that generators using single circuits to Islands could claim sharing under ALF, has been removed by the change (in the Original and all ALF WACMs) in MITS definition. We believe that the case for incorporation of parts of the HVDC Converter Stations into the Non – Locational part of the charging methodology to be justified by the evidence submitted and that the evidence is robust enough to suggest that 60% for 'Bootstraps' and 70% for Island Links is justified. We therefore consider all WACMs including ALF and HVDC reductions (WACMs 7,14,21,22 and 28) to be better than the Original. **We consider WACM7 (ALF + HVDC 'Bootstraps' 60% /HVDC Island links 70% into non-locational + CCF) to be BEST against the CUSC objectives.**

Do you support the proposed implementation approach? If	We would support implementation in as soon as is practicable, and would prefer April 2014. We realise that this timescale is

not, please state why and provide an alternative suggestion where possible.	tight and therefore would accept that the actual implementation date would be at the discretion of the Authority.
Do you have any other comments?	

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Paul Jones* *paul.jones@eon-uk.com*
Company Name:	*E.ON*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*No. We do not believe that any of the options for CMP213 better meet the applicable objectives. Our concerns mainly relate to the sharing proposals which we do not believe are cost reflective as they do not reflect the manner in which investment is made in the transmission system. Our comments on each of the main elements of CMP213 are attached in a separate annex.* *We would however be supportive of a modification which did not include the sharing elements, but did include certain proposals for the treatment of HVDC assets which parallel the main transmission system and island charging.*

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	*No. Notwithstanding our view that none of the options should be implemented, we would have preferred to have seen a strong signal sent in the methodology that implementation prior to April 2015 would simply create winners and losers, for the reasons set out in 9.24 of the consultation.* *It should also be pointed out that it is not necessary for CMP213 to be implemented in April 2014 to provide investment signals. No plant is going to be able to be built in time to take advantage of an April 2014 start date other than that which is already under construction (ie investment decisions taken in the context of the*

	old locational signals).
Do you have any other comments?	*Yes. Please see the attached annex.*

Annex - E.ON comments on the main elements of CMP 213

1. E.ON's comments on the main elements which go to make up the original proposal for CMP213 and the various alternatives follow. Over all, due to our overriding concerns regarding the sharing element of the proposals, we do not believe any of the options better meet the applicable objectives than the current baseline. However, if a modification was to be raised which did not include any of the sharing options, but did address charging for HVDC circuits which parallel the main onshore transmission system and island charging, we believe that this would have the potential to improve the arrangements over the baseline.

Sharing

2. We believe that the charging regime should reflect the way in which investment is made in the transmission network in order for the correct signals to be sent to generators. Whilst we understand the theory behind the proposals to change charging to reflect sharing, we are not convinced that it accurately represents the reality of how investment is made. Whilst future investment may increasingly be made on the basis of a cost benefit analysis considering both constraint costs and network investment costs, it is not clear that this will result in a perfect equilibrium situation whereby investment is made until the marginal costs of network and constraints are equal. This is the assumption which is made to justify charging network investment costs in line with factors which actually influence the level of constraint costs.

3. We also do not agree with the current proposed method for allocating circuit costs to the peak charge and the year round charge respectively. This allocates a circuit based on the conditions under which it is most loaded when modelled in the transport model. However, there are two issues with this. Firstly, the model is based on an intact system, whereas the network is planned to ensure that it can cope with any network outages under ACS peak conditions (SSQS 4.6), whilst for the rest of the year, network investment is assessed using only planned transmission outages, taking account of the opportunity to reschedule generation and network outages (SSQS 4.7). In the current charging methodology this is not an issue as the effect simply to understate the cost of the network which can be corrected using the application of the 1.8 security factor. However, under CMP213 this can result in circuits being allocated to the wrong charges altogether. As the peak and year round charges are applied in considerably different ways this could result in significant errors in the costs incurred by generators resulting in sub optimal transmission investments being made.

4. Secondly, it is not clear why a circuit should only be allocated to one charge. If a circuit is more heavily loaded on the peak background than the year round background it doesn't necessarily follow that it will not need to be reinforced to support year round operation of new wind plant. Similarly, just because a circuit is more heavily loaded under the year round background, it doesn't mean that it will not need to be upgraded to meet peak conditions. Therefore, as an alternative, circuit costs could be pro rated between the different charges in some manner.

5. There are a number of different approaches for doing this. One approach would be to regard meeting peak demand security as a priority consideration with the optimising of

investment/constraint costs as a secondary consideration, albeit an important one. Therefore, if a circuit is loaded 1000MW under peak conditions and 1200MW under the year round background, 1000/1200 of the cost could be allocated to the peak charge and 200/1200 could be allocated to the year round charge. Alternatively, the costs could be allocated in proportion to the ratio of the loadings.

6. We also note that the incremental costs of increasing a circuits' capacity are non-linear, and if such a methodology were adopted, it would be appropriate to include this important effect. To be explicit, to build a circuit with 1000 MVA capacity, or 1200 MVA capacity, the same number of overhead line towers are required. Marginally larger conductors are required, and potentially marginally stronger conductions are required. It is not 20% more expensive to build a 1200 MVA line compared to a 1000 MVA line.

7. Additionally, we believe that the use of a historic average load factor (ALF) to reflect the impact that a generator has on constraint costs is incorrect. Firstly, it has been shown in the analysis undertaken by the workgroup that load factors are not the sole determinant of constraint costs. Other factors such as the diversity of plant behind boundaries and bid prices are important too. The original proposal for CMP213 ignores these other factors so, even if you were to accept the premise that charges for network investment can be scaled by factors which affect constraint costs, it does not even adequately reflect those factors. The alternatives which attempt to reflect diversity could be seen as improvements in this respect.

8. The diversity options have been described as more complex than the original proposal, but we disagree. They may be more complex for National Grid to calculate, but this certainly should not be an issue for users. Users need to model future charges and understand how current charges have been set. They presently do this by running a version of the transport model provided by National Grid. The complex part of this is deciding on the data to be used in the modelling. The transport models will be different for the various approaches for sharing under CMP213, but the data required to run them should be similar if not the same. Therefore, the diversity options should be a more accurate approach than the original with little or no additional complexity for users compared with the original proposal. Nevertheless, if CMP213 is implemented then there will be a step increase in complexity compared with the current baseline, as users will not only have to model generation and demand changes in the future, but also generation load factors and the backgrounds against which charges are allocated to the peak and year round charges.

9. Secondly, a historic load factor is not a good representation of future load factors. The methodology is forward looking and is therefore designed to reflect a generator's impact on future network costs. Therefore, it is a generator's future load factor which must be relevant. Also, if a signal is being sent to generators in this way there must be some appropriate response that is being sought from them. As the new signal is proportionate to load factor, then it would imply that the response from the generator should now be based on load factor, as well as related to where and when a new station should be built or an existing station closed. If a generator cannot respond to this signal by changing its load

factor, as historic load factors will be used for its charge anyway, then purpose of the signal is unclear.

10. It is also obvious that historic factors will be wrong in the next few years. HMG has implemented an increasing Carbon Support Price which will result in gas becoming the preferred fuel for generation over coal from around 2015/6. In addition, the IED (in effect from 2016) will restrict the load factor of coal plant significantly below currently seen levels.

11. Finally, an important issue with the proposals for sharing is that they create an inconsistency between the charging for generators and demand. Demand charging will remain largely unchanged by these proposals. At a time when significant importance is put on the encouragement of more demand side participation in the market, as an alternative to generation capacity, it is not sensible to be introducing greater obstacles to them competing on a level footing, through more differential charging regimes.

HVDC

12. The present methodology is not designed to reflect HVDC so the original is at least an improvement in this respect. The proposal for choosing the impedance of an HVDC circuit for use in the transport model seems the most appropriate way to ensure that it is neither over nor under reflected in locational charges. The proposals for the treatment of converter stations are less straight forward to assess, as whatever approach is chosen seems to introduce inconsistencies into the methodology.

13. If the full costs of converter stations are included into the expansion factor for the relevant cable then this would be consistent with the treatment of HVDC cables for offshore wind projects, but may be contradictory to the treatment of AC substations which are socialised through the residual charge. However, if all or some of the costs are removed from the expansion factor, then this is inconsistent with the treatment of converter station costs for offshore wind projects.

14. If it is decided that some level of converter station costs should be removed, then we believe that this should be calculated on a case by case basis and should only seek to remove the equivalent costs that would be socialised for AC substations. There is no justification for removing generic proportions of the costs of converter stations. The generic proportions used in some of the alternative options were derived using a very limited data set, and are highly unlikely to be representative of specific projects. A specific approach to reflecting costs would be more appropriate and would be consistent with that used in respect of offshore connections. In the case of offshore connections National Grid and Ofgem both supported a specific approach when they respectively proposed and approved GBECM08, which brought in the offshore charging regime. This was on the basis that there was insufficient data on the costs of offshore connections and costs of different projects would be too dissimilar to justify a generic approach. These characteristics are equally applicable to HVDC assets, if not more so. Therefore, a consistent approach would be to opt for a specific allocation of costs for HVDC too.

Island Charging

15. Similar to the situation with HVDC assets, the current methodology was not really designed to accommodate the connection of islands through single spurs to the mainland. This is not necessarily an issue which is unique to islands. However, the circumstances where part of the network with redundancy built into it is connected to the main transmission system through assets with little or no redundancy, is most likely to occur in respect of island connections. We support the approach provided by the original modification as an improvement on the baseline.

16. In respect of HVDC assets connecting islands to the mainland, we believe that an approach should be adopted which is consistent with that chosen for HVDC assets which parallel the main transmission system. Again, we believe that costs should be reflected on a case by case basis, including any options which seek to remove part of the costs of converter stations from the costs of island HVDC links.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Amisha Patel, Regulatory Analyst*
Company Name:	*ESB*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.* ESB welcomes the opportunity to provide comments on CMP213. We note and appreciate the work that has gone in to developing the suite of proposals contained therein. Whilst there are some elements of the Original and proposed WACMs that better facilitate the applicable CUSC objectives than the baseline, we do not believe that any proposal brings these together to better meet the applicable CUSC objectives than the baseline. We provide our reasoning below.

	Sharing and diversity Peak security: The original proposal has been raised on the basis that, as well as ensuring the transmission network is robust at times of peak electrical demand, the network is increasingly planned on a cost-benefit basis that reflects the year round operation of the system, and that implicit within this, some network sharing takes place between generators. Hence the proposal aims to better reflect this through splitting the tariff into two elements; (i) Peak Security and (ii) Year Round. The Original and diversity options 1 and 2 all assume intermittent generators (e.g. wind, solar and wave) do not contribute to peak security, and are therefore not exposed to this element of the tariff. We believe it is not cost-reflective to assume that all intermittent generation does not contribute to meeting peak demand. The analysis that underpinned GSR009 concluded that intermittent generation currently contributes around 5% of generation at periods of peak demand. For ease, this was reduced to 0% for the purposes of SQSS. As increasing amounts of diverse intermittent technologies are connected, this contribution can only increase. Therefore, we do not believe that it is appropriate to not apply (at least a proportion of) the costs of meeting peak demand to intermittent generation in this arbitrary way. For these reasons, we do not believe that any of the options that arbitrarily split generation in this way are more cost-reflective than the baseline and therefore fail applicable objective (b). Annual Load Factor (ALF): As we have stated throughout the workgroup process, we do not agree with the use of ALF as a proxy for constraint costs (which underpins the Original and diversity options 1 and 2). There are a number of other significant factors that contribute to generators' impact on constraint costs. In particular, the mix of generation bids and offers behind constrained boundaries plays a much more significant role in determining the level of costs associated with managing those constraints. This has been supported by analysis done as part of CMP213. We therefore believe it is this that should be the key driver in any diversity calculation within the charging methodology. The CMP213 Original and WACMs that are predicated on ALF do not, therefore, better facilitate applicable objective (b). In addition, we are concerned that the use of ALF in calculating charges begins to smear the long term locational signals of TNUoS charges and the shorter term operational signals within BSUoS charges, particularly for conventional thermal generation. For most intermittent technologies, load factors are relatively stable across years. This is not the case for thermal generation, which is subject to extraneous market pressures, resulting in material changes often in short timescales. We are concerned that the use of ALF in the ways proposed could have detrimental

	impacts for competition between fuels and within different classes of technologies as the effects of changes in running regimes are (or not) filtered through to charges. Any option using ALF does not, therefore better facilitate applicable objective (a). It has been recognised that the relationship between load factor and incremental constraint costs deteriorates in areas with little diversity between generation plant types. This is particularly the case in areas with large amounts of low carbon generation, where the price to constrain off generation can be expensive relative to conventional generation. We believe that of the options presented diversity method 3 could potentially better reflect costs. However, whilst diversity method 3 does not use ALF to determine charges and is therefore marginally better than the other change proposals, we do not believe it to be as cost-reflective as the baseline. **HVDC** There is clearly a need to update the charge calculation methodology to reflect new HVDC technologies. Considering the changing nature of the transmission system, we agree that it is necessary for the methodology to robustly incorporate HVDC technologies. We strongly believe that that the current high-level principal that the costs associated with investment should be recovered from those that cause and/or benefit from that investment should be maintained and that arbitrary splits to facilitate investment in one area or type of technology should not be introduced. However, we also note the current treatment of non-distance related, fixed cost assets. Wherever possible, we would seek to see principles adopted that could be applied to different aspects of the charging methodology. In particular, we would welcome a methodology for incorporating HVDC parallel links that could also be applied to island links, without special amendment. As such, we are of the view that the option that best facilitates the inclusion of HVDC, whilst also facilitating the applicable objectives, is the removal of a specific percentage of the converter station (and associated/similar assets) costs based on those elements that are similar to elements of the AC transmission network that are currently not included in the locational signal and whose removal can be robustly justified on that basis. We believe this would be the most appropriate way of incorporating such links in to the methodology and would welcome a future modification to the current baseline methodology along these lines. **Islands** As per previous comments, we are of the view that that there is little reason why the charging basis for island connection should be different to that for generation elsewhere in GB. Of the options provided, we would support the removal of specific percentages of converter costs based on those elements that are similar to elements of the AC transmission network that are

	currently not included in the locational signal and whose removal can be robustly justified on that basis. Again, and as above, this is would be the most appropriate way of incorporating such links in to the methodology and would welcome a future modification to the current baseline methodology along these lines.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We would strongly seek for an implementation date of no sooner than 1st April 2015 as this would give generators more notice for taking account of changes within commercial arrangements. For similar reasons we would urge for Ofgem not to introduce any changes mid-charging year.
Do you have any other comments?	While we understand the arguments in favour of encouraging the development of renewable schemes in areas of high renewable potential such as the islands, we do not accept that the GB transmission charging methodology should be used as a basis for providing additional subsidy for such schemes. If a subsidy is provided through transmission charges (implicitly or explicitly) it will inevitably lead to economically inefficient investments, increased overall cost and an undue deterioration of competition in the generation market. We therefore believe that any subsidy should be made explicit and provided outside of the charging regime.

Fairwind (Orkney) Ltd

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E-mail: dennis@researchrelay.com
Date: 9th May 2013

CUSC Team
National Grid
Warwick
UK

Fairwind Orkney Ltd – response to CMP213 Code Administrators Consultation

Thank you for the opportunity to comment on the above document.

We believe that the Original and those WACMs including the Annual Load Factor (ALF), reductions in the Locational element for HVDC converter stations, CCF for Local Transmission Circuits and to a lesser extent diversity 1 to be better than the baseline with respect to the Applicable CUSC Objectives for the following reasons:

These options are more likely to facilitate competition between generators offering a range of fuel sources including renewable natural energy sources which are not subject to volatility due to geo-politics or competition for the fuel source. High and volatile TNUoS charges in some peripheral areas of the UK Transmission Network have been a perceived barrier to entry for new generators in those areas and this issue was a key part of Project TranmsiT, which, in turn, gave rise to the instruction to National Grid, by Ofgem, to raise a CUSC modification.
Sharing as defined by ALF, and underpinned by a recent review of the SQSS (NETS SQSS GSR-009) which concluded that future investment would include parameters of variable output rather than on a deterministic level, offers a method which is more cost reflective of future build whilst offering relative simplicity and transparency.

A change in the MITs definition for charging, proposed under the Original, which would rule out ALF for single circuit links together with a Counter Correlation Factor (CCF) for Local Circuits, would serve to remove a potential anomaly should ALF be adopted.

We consider that better competition will also be realised if newer technology assets such as HVDC transmission links can be brought into line with current treatment, in charging terms, of more conventional AC assets. In particular, through evidence presented to the Workgroup, significant parts of the HVDC Converter Stations and associated equipment carry out the same actions as Sub-stations and voltage regulation in AC circuits which are classed as fixed rather than Locational assets for charging purposes.

The above named options are likely to offer better cost reflectivity - in that future Transmission grid reinforcement is likely to be based on a more Cost Benefit approach where the balance between sharing, constraint costs and security of supply lead to a volume based rather than capacity based solution. ALF and the treatment of HVDC commensurate with AC assets seem to strike the correct balance between absolute cost reflectivity, whilst maintaining Locational signals, and simplicity and transparency in charging.
We note that Diversity 1 (a mix of ALF and non-sharing elements) attempts to be more cost reflective in areas where there is a domination of a single type of generation (onshore wind is used as a proxy for this in most of the Workgroup deliberations) – but in our view the limitation to the model based entirely on predicted constraint costs across boundaries without modelling any possibility of sharing between generators of a similar type (and in particular wind developments on widely spaced sites amongst differing terrain) reduces simplicity and transparency whilst increasing potential volatility.

We consider Diversity 2 and 3 to be marginally worse than the baseline in that the 50% limit to sharing is arbitrary and offers the potential for significant volatility in peripheral areas of high renewable energy resources. We consider that cost reflectivity could be distorted with unjustifiably high price signals in the North of the UK and the Scottish Islands.

Our preferred options also take account of the Developments of TO's businesses and the Transmission System. ALF and the equal treatment of HVDC plus CCF for Local Circuits are more likely to reflect the way in which TO's will need to plan and build Transmission infrastructure in the years ahead. The new Transmission Grid will need to connect new sources of energy which are fixed because of the nature of the resource (tidal stream, best wind and wave resources) and to be flexible enough to reduce costs to the end consumer.

We consider that the 'Best' option arising from CMP213 also needs to fit with the aims of Project TransmiT and to offer the best value for money for consumers going forward. We note that for TransmiT -
"The aim of Project TransmiT is to ensure that we have in place arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers."

The beneficial impact on Consumer Bills going forward (as shown in WG Report Vol 2 p243), and the encouragement to low carbon energy generation in areas where it is most available plus development of high quality and efficient transmission network through HVDC links to the Scottish Islands and links Parallel to the existing AC network is significant.

For the reasons above we suggest that WACM 7 is the 'Best' against Applicable CUSC objectives.

Yours sincerely,

Dennis Gowland
Director – Fairwind Orkney Ltd

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

<table>
<tr><td>Respondent:</td><td>Simon Lord
Head of Transmission Services
GDF SUEZ Energy UK-Europe

Tel. +44 (0) 1244 504601
Mob. +44 (0) 7980 793692
simon.lord@gdfsuez.com</td></tr>
<tr><td>Company Name:</td><td>GDF SUEZ Energy UK-Europe</td></tr>
<tr><td>Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.</td><td>Yes , WACM that implement the following are an improvement:

Diversity Methods 1 or 2
Load factor ALF or Hybrid (preferred)
Parallel HVDC 50% converter cost socialised or specific
Island HVDC 50% converter cost socialised or specific

<table>
<tr><td>WACM</td><td>Diversity 1</td><td>Diversity 2</td></tr>
<tr><td>50% converter Cost</td><td>30/33</td><td>31</td></tr>
<tr><td>Specific converter cost</td><td>23/26</td><td>24</td></tr>
</table>

Overall our most favoured WACM is 31 made up of Diversity 2 historic ALF and 50% of converter costs shared.</td></tr>
<tr><td></td><td></td></tr>
</table>

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	*Yes we agree with the implementation methodology. Although we have concerns that implementation prior to April 2015 may subject some users to charges that they cannot avoid even if they have given notice of closure.*
Do you have any other comments?	*Yes see below*

Diversity

The working group has identified that the key drivers for transmission investment are diversity, load factor and bid price. All three characteristics are required in order to reflect the impact a user has on transmission investment.

We believe, based on the evidence presented in the report, that the original proposal does not improve on the current arrangements as it takes no account of bid price and diversity of plant type. The report clearly shows that the cost of providing transmission in constrained areas can be significantly higher than would be determined using just load factor.

A charging methodology that uses only load factor will result in a significant burden being placed on all users (through the residual charge) to finance load related infrastructure in areas dominated by one plant type. It will potentially encourage intermittent (wind) plant to locate in areas that already have high wind penetration resulting in significant reinforcement costs that are not reflective of the costs imposed on the system by the user. Some element of diversity is necessary in the tariff calculation.

The group has developed a number of credible options that deal with this effect in a practical and balanced way. The diversity proposals whilst capable of further incremental development move the transmission charging methodology in an appropriate direction.

The three diversity options bring in elements of diversity and bid price in various ways to better reflect investments in the transmission system. In areas where there is low diversity and high bid prices charges are adjusted to reflect this. The control mechanism encourages users to locate in areas of the transmission system where they can be accommodated at least cost.

We prefer an alternative that includes an explicit load factor element. Diversity 1 and Diversity 2 both have explicit load factor element and share many similarities in design. Diversity 1 has a stronger load factor element resulting in pure load factor charges in many areas of the transmission system. Diversity 2 takes account of diversity in areas where there is a significant volume of thermal plant and encourages low load factor intermittent plant to locate in these areas. Diversity 2 allocates a proportion of the incremental transmission cost to TEC and the remainder to load factor. This recognises that even where there is perfect sharing a minimum amount of transmission is required; this is set at 50% in the proposal. It is recognised in the report that the 50% factor can be adjusted within groups with additional counter correlation factors once experience of actual sharing is established.

The report recognises that within the various options for diversity there may still be incremental change required with counter correlation factors for various plant groups and types. We expect that these will be dealt with via incremental change over the next few years and should not detract from the more fundamental decision of how to include diversity.

We prefer Diversity 2 over Diversity 1 as we believe that it is more capable of being crafted to include future developments as and when they occur and it manages negative transmission zones in an effective way.

Load Factor

The use of load factor in the various alternatives is designed to reflect the design decision and not the actual load factor. For some types of plant (wind) the load factor is a given within general geographic areas but for thermal plant load factor it is driven by market economics. Over time the load factors of thermal plant will change; thus, if load factor is to be used (and hopefully the planners should reflect this in the design of the system) then allowing one off events to be removed is appropriate. Given this, whilst we prefer the hybrid option, the original option also has this facility; hence we are supportive of both options.

Parallel HVDC and Islands converter costs

The report has identified (from one source) that to be treated on an equivalent basis with conventional substations some 50% of the cost of a HVDC converter stations costs should be socialised. The 50% figure could be high or low and only a specific calculation for each converter station would achieve accurate results. We support both the specific approach and the generic approach with the 50% figure being used as a pre-estimate of the socialised cost on an equivalent basis. On balance we believe the generic 50% approach is appropriate as this would avoid significant work establishing the specific number for each HVDC installation.

Whilst we recognise that in some circumstances HVDC converters could provide additional benefits this is unlikely to be the case for all HVDC converters; thus we do not support the Quad Booster or additional reactive capability on a generic basis. We do believe that a specific alternative could be developed as part of incremental change to cover these two areas.

Split load flows (peak and year round)

We have concerns as to the use of split peak and year round load flows. Whilst evidence has been presented that demonstrates much of the work presented by the group there is little   evidence presented for the use of split load flows. The only rational given is that it is used in the SQSS. The SQSS use is principle around ensuring that transmission is available to secure demand in periods of low intermittent output. The proposer has then made the assumption that on this basis intermittent generation should not be charged for this element

of transmission. We believe that all generation should contribute to the incremental cost of transmission and to arbitrarily split the load flow based on a second generation back ground (with no intermittent generation) but using an identical demand background is inappropriate and serves no purpose other than to reduce intermittent generation tariffs.
Increasing levels of intermittent generation do have an effect on demand security by reducing the levels of conventional generation and as such all generation types should be exposed to the full years round tariff element based on a single back ground.

It is unfortunate that the option of a single load flow has not been presented by the working group as a WACM driven by the need to ensure only a manageable number of alternatives were put forward. We would expect this issues to be picked up as incremental change should a dual load flow option be approved.

Highlands and Islands Enterprise
Iomairt na Gàidhealtachd 's nan Eilean

cusc.team@nationalgrid.com 09/05/2013

Dear CUSC Team

Highlands and Islands Partnership Response to CMP213 Code Administrator Consultation, May 2013

Highlands and Islands Enterprise (HIE) is the Scottish Government's agency responsible for economic and community development across the North and West of Scotland and the islands. Renewable energy resources in the Highlands and Islands constitute the greatest concentration of potentially exploitable renewable energy resources in the UK and the region is well placed to contribute to UK and European carbon reduction and renewable electricity generation targets *if* key regulatory barriers can be effectively addressed to facilitate deployment of renewable technologies.

HIE along with its local partners: the democratically elected local authorities covering the North and West of Scotland and the islands: **Shetland Islands Council, Orkney Islands Council, Comhairle nan Eilean Siar, Highland Council and Argyll & Bute Council** make representations to key participants on behalf of industry to influence the way in which grid construction is triggered, underwritten then accessed and charged for in the region. This is because it has a significant bearing on the economics and deliverability (and hence the exploitable resource) of projects in our area.

HIE and its partners are pleased to have the chance to contribute to this final consultation on transmission charging methodology. We have been involved in the whole Project TransmiT process over the last 2 ½ years, including closely following the exhaustive and thorough deliberations of the CUSC Working Group over the last 9 months. We regard the current consultation on transmission charging methodology as being of crucial importance to the future of the important renewables industry in the Highlands and Islands – and by extension, crucial to the future development of the whole economy of the Highlands and Islands.

At the same time we are cognisant of the CUSC objectives against which the CUSC Original and Alternatives require to be measured. We recognise the importance of "effective competition in the generation and supply of electricity" and of "charges which reflect, as far as reasonably practicable, the costs….incurred by transmission licensees in their transmission businesses." We also recognise and support the carbon-reduction and renewable energy objectives of both the UK and Scottish Governments, which form the strategic policy framework for energy development.

We believe that the rich renewable resources of the Highlands and Islands – wind, wave, and tidal stream – are a crucial strategic asset for the UK now and even more so in the future. Our vision is for the Highlands and Islands to be an important part of the future electricity supply to the UK consumer, from a diverse range of renewable resources, making a major contribution to affordability and security of supply for consumers as fossil fuels become ever more expensive and scarce. In time the region will be an integral part of the onshore and offshore transmission network bringing renewable energy from the periphery of the UK to centres of population.

A transmission charging methodology which meets the CUSC objective of facilitating competition in generation and supply is not in conflict with this vision, indeed a transmission charge which was a barrier to development of renewables in the Highlands and Islands would not be compliant with the requirement to facilitate competition. Likewise cost-reflectivity needs to be seen against the need to develop the infrastructure for the changing realities of future UK energy supply.

Turning to the specifics of the Consultation Document, and to the first question whether CMP213 better facilitates the applicable CUSC Objectives, we comment below on the main themes in the Original and Alternatives.

1. Diversity

We support the principle of network sharing by intermittent generators which are not using the network all the time, on the grounds that this best reflects the costs which such generators impose on the transmission network. Use of the Average Load Factor to reflect this provides simplicity and clarity, and perhaps most importantly, stability. Application of diversity factors introduces uncertainty for investors, with the possibility of substantial transmission charge variability arising from changes by other generators in the same zone – the retirement of carbon generation or the introduction of substantial new renewables generation.

Sharing may in any case take place in zones with a preponderance of renewable generation, either through diversity or geographic dispersal, e.g. in a large zone such as the North of Scotland, wind generators in scattered locations may well experience different wind regimes thus resulting in some counter-correlated usage of the network. Counter-correlation is very likely where diverse renewables technologies are connected to the grid, as demonstrated by the Heriot-Watt research, to which we refer again below.

On this basis we believe that the sharing mechanism in the Original, which uses Average Load Factor, provides the best alignment with the CUSC objectives.

2. HVDC Options

In our view, by analogy with the treatment of AC substations, and in the light of the added resilience to the system as a whole, converter station costs should as far as possible be excluded from the calculation of transmission charges for use of HVDC cables. We therefore support those options which remove 50% of the cost of converter stations from the calculation.

3. Islands

The three island groups of Western Isles, Shetland and Orkney account for a significant proportion of the renewable resources of the Highlands and Islands. This is particularly so of wave and tidal stream resources, indeed the islands are key to the development of marine energy technologies which could be the basis of a major new industry for the UK, as well as providing increased supply security for consumers. We believe that the HVDC cables planned for the islands, which could well be the fore-runners of a denser integrated network, should be treated in the same way as HVDC on the mainland for charging purposes, namely though the exclusion of at least 50% of converter station costs from the calculation of user charges.

We note and support the proposal that the security factor for single circuit interconnectors to islands should be 1.0 rather than 1.8. We also note that the islands expansion factor should be specific to the costs of each island connection. This position is the culmination of much discussion over the whole course of Project TransmiT, including other proposals which would have effectively involved some averaging of costs over a wider area. Such proposals would have gone some way to reduce the high cost to island generators of building basic multiple-user network infrastructure. Nevertheless in the context of the overall CMP213 proposal we accept that an islands expansion factor reflecting individual island connection costs best meets the CUSC objectives.

Finally is respect of islands, we strongly support the concept of network sharing by different renewables technologies, and the mechanism of the Counter-Correlation Factor devised by the CUSC Working Group to reflect this. The Heriot Watt research, based on actual data from Orkney, represents a robust basis for this principle, which we believe will be demonstrated in practice in all three island groups once diverse technologies are connected.

The rejection of the principle of anticipatory application of CCF is in our view regrettable. Network sharing by diverse technologies is the most efficient use of expensive new cable, and thus beneficial to consumers, and we believe that it should be encouraged as much as possible – which anticipatory sharing would have done. Nevertheless we hope that this first step in the acceptance of the network sharing principle, will provide a basis for developing the treatment of the principle in the future, possibly through further CUSC modification.

4. MITS definition

We note the intention to modify the CUSC Section 14 definition of MITS for spur connections, so that a GSP and two transmission cables will not lead to a MITS designation, but that this will be dependent on two island/mainland interconnectors – and that this will lead to a security factor of 1.8. We recognise the need for this move in terms of the overall CMP213 proposal, particularly the use of ALF for sharing on the mainland, although with some reservations about the potential wider implications, and unintended consequences, of such a modification. We believe that the specific purpose of this modification should be acknowledged.

5. Implementation

In our view, implementation should take place as rapidly as is practicable. There is considerable investor uncertainty in the Highlands and Islands – and this has been the case for a good number of years, even prior to the start of Project TransmiT in September 2010. This has been harmful to investor confidence, and has meant a deterioration in project viability in some cases, most notably in the Western Isles where uncertainty has resulted in reluctance to commit on the part of both developers and Transmission Owner, with consequent delays to projects. Plans in many cases are in abeyance until there is certainty about transmission charges. Illustrative charges are helpful but they are an inadequate basis on which to finalise financial plans. We believe that there is time for Ofgem to make its decision and introduce new charges for 1 April 2014.

In respect of the need for transition arrangements, we recognise the need to safeguard system security, and believe that others are best placed to judge whether this imperative requires that transition arrangements be introduced.

Conclusion

The consultation document is a comprehensive document which reflects the depth and range of the Working Group's deliberations. The matters which it covers are of immense import to the Highlands and Islands, and our partnership has followed these deliberations with great interest. We believe that the direction of travel points to, and justifies, significant change to the status quo in charging methodology, to better meet the CUSC objectives and to better equip the UK to meet the challenges of the new imperative to decarbonise the country's electricity supply. In terms of our views of the key themes set out above, we believe that WACM 7 best fulfils these purposes, and we therefore support the adoption of that Alternative by the CUSC Panel and by Ofgem, with implementation by 1 April 2014. We note that the Consultation analysis shows that this option is the most beneficial for consumers, in terms of impact on annual bills, and that this constitutes a strong argument in its favour.

We hope you find these comments useful and look forward to viewing your conclusion and recommendation in due course. If you would like to discuss any of the points raised in this response, please don't hesitate to contact me.

Yours sincerely,

Elaine Hanton

Elaine Hanton
Joint Head of Energy
Highlands and Islands Enterprise

In partnership with:
Shetland Islands Council
Orkney Islands Council
Comhairle nan Eilean Siar
Highland Council
Argyll & Bute Council

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	Andrew Wainwright, andy.wainwright@nationalgrid.com
Company Name:	National Grid
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	National Grid has provided its view on the Original proposal and Workgroup alternatives in the Code Administrator Consultation. However, for clarity we set this out again below. In terms of sharing, we believe that the diversity 1 alternative increases the level of cost reflectivity above the Original proposal through better accounting for transmission investment decisions in areas of the system dominated by low carbon generation technologies. However, we recognise that this adds a significant level of complexity to CMP213, and such complexity can reduce a user's understanding of the TNUoS methodology, and hence reduce the overall competitiveness of the market. Overall we believe that the increase in cost reflectivity of the diversity 1 alternative outweighs the additional complexity introduced to the methodology. Additionally we are not supportive of alternatives proposing the calculation of Annual Load Factor via User forecasts (hybrid alternatives) as we believe that this introduces complexity and therefore additional costs for Users and NGET, whilst not taking a long term view of a generator's impact on transmission investment. In terms of parallel HVDC circuits, National Grid recognises the need for this technology to be incorporated within the TNUoS charging methodology. We have welcomed the evidence brought to the Workgroup to demonstrate that a reduction in converter costs would be consistent with the treatment of existing onshore AC technologies already incorporated in the charging methodology. Indeed we believe that there are strong arguments in favour of the removal of either 50% or 60% of such costs. Recognising the benefits this technology brings in

	controlling flows on the National Electricity Transmission System, we have a preference for the alternative proposal to remove 60% of converter station costs from the calculation of the expansion factors for this technology. Similarly, in terms of island circuits, we also recognise the need for such technologies to be incorporated within the TNUoS charging methodology. Again we have welcomed the evidence brought to the Workgroup to demonstrate that a reduction in converter costs would be consistent with the treatment of existing onshore AC technologies already incorporated in the charging methodology. However whilst we believe that there are strong arguments in favour of the removal of up to 50% of these costs, we are yet to be convinced of a strong need case, in the majority of situations, for voltage management solutions in affected areas of the system, and hence the overall benefit to the end consumer of this technology. We therefore support the removal of 50% of the converter station costs for island circuits. We note the alternatives considering specific rather than generic converter cost reductions, and understand that this could improve the cost reflectivity of circuits on a case by case basis. However we have concerns in regards to the overall benefit of such an approach when accounting for the additional resource requirements. We therefore see such an approach as a potential future enhancement to the TNUoS charging methodology.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	National Grid believes it is appropriate for the Authority to determine a suitable implementation date, and that it is the role of Industry to provide sufficient evidence to enable a robust decision to be made. We believe that an implementation date of April 2014 is achievable, but note concerns from Industry regarding the need for sufficient notice of any proposed change to the methodology and therefore customer charges. If notification of a change to the methodology is not made in a timely manner, then it is likely that at best Users will have contracted based on the existing methodology and potentially added a risk premium to their pricing to account for uncertainty due to CMP213. Hence it could be more efficient for the end consumer to delay implementation to the start of the following charging year. In either case, we would be happy to provide additional indicative tariffs for customers to assist their understanding of potential changes, but note that this would remove the uncertainty.
Do you have any other comments?	As part of the Authority direction from the Project TransmiT SCR, National Grid were required to ensure that any Modification proposals developed were supported by a robust evidence base.

	Thus, National Grid, with input from the CMP213 Workgroup, has undertaken impact assessment to illustrate the future potential industry impacts of different options under CMP213. This has used the same models as developed by Redpoint for the Ofgem Project TransmiT SCR Impact Assessment. Initial analysis results were made available to the CMP213 Workgroup, and have been included in the Code Administrator Consultation. Subsequently we have refined our model to better reflect the current industry position in regards to EMR proposals (capacity mechanisms) and notified changes to the generation background, and provide in Annex 1 of this response revised results. Full details of updates made to the models since the Project TransmiT SCR Impact Assessment are provided in Annex 2. We have also employed Redpoint to audit the changes made to the model, and confirmation of this is also provided in Annex 2. The spreadsheet containing the information underlying the data presented in Annex 1 is available from National Grid. In addition, we will make available the 2014/15 illustrative transport and tariff models created as outputs from this impact assessment. These are based on 2012/13 generation charging zones, and their release is subject to the normal licence agreements. For a copy, please contact the code administrator at: cusc.team@nationalgrid.com

Annex 1 – Revised National Grid CMP213 Impact Assessment Modelling Results

This annex contains draft results for the revised CMP213 Impact Assessment modelling undertaken by National Grid in April 2013 including a high level commentary.

High Level Commentary

This commentary provides a high level interpretation of the results contained within this annex. This involves a general overview followed by separate comparisons with the TransmiT SCR results, between Status Quo and Original models, and between the Original and the four modelled alternatives; HVDC at 50% converter costs, Diversity 1, Diversity 2, and Diversity 3.

<u>General comments</u>

- The differences between the options modelled are finer in this analysis than those compared in the TransmiT SCR.
- The modelling is of a single scenario only and therefore does not have an estimate of the variation of the results across different commodity prices or renewable targets. Hence it does not account for the broad uncertainty in the outcomes of EMR. Therefore the deltas in the CBA between model runs should be treated with caution and interpreted in the context of these comments.
- The consumer bill impacts are inherently more uncertain given the large impact of small changes in capacity margin, and the uncertainty around the design of the capacity mechanism.

<u>Comparison to TransmiT SCR results</u>

- In the SCR modelling, renewables to continue to grow after 2020, to 40%. This led to transmission reinforcement in the 2020s that are not observed in the new results. In the new results, there is more nuclear in 2030 (due to nuclear extensions, and a specific target agreed by the CMP213 workgroup) and more CCS, which is why targets are still met.
- The new results have less new onshore wind (2020: 5.6GW vs. 7GW in the SCR) and more offshore (2020: 9.5GW vs. 7.6GW in the SCR). This reduces the need for onshore transmission reinforcement. Therefore, compared to the SCR results, there are fewer HVDC lines being built.
- Fewer HVDC reinforcements means fewer step changes in Northern Scotland tariff levels.
- These results have constraint costs that are slightly lower from the outset, and very low from 2020. This is closely related to the point above about reduced onshore wind.

<u>Comparison across results: Status Quo to Original</u>

- Overall both models give very similar outputs. Capacity margins are similar throughout.
- The Original gains Scottish onshore wind and more northerly offshore wind, and loses southerly offshore wind.
- The Original has slightly lower renewables in 2020 and 2030
- Locational differentials are less for the Original than Status Quo.

- The Western HVDC in 2016 has broadly similar impact on tariffs for 70% conventional plant as Status Quo.
- CBA to 2020;
    - The major saving for the Original is in generation costs (mainly capital expenditure due to the replacement of offshore wind with onshore wind). However the slightly lower renewables level under the Original will also be contributing to this.
    - There is also some saving in transmission costs up to 2020 in the Original which is due to savings in offshore wind OFTO transmission
    - The Original has higher power prices with a similar capacity margin. Capacity payments are virtually identical
    - Overall cost to consumers is higher under the Original, however this is mainly a wholesale price effect – the other underlying costs reduce.
- CBA 2021-2030;
    - In this period there is no longer a saving in generation costs other than when carbon is included
    - In this period there is a net transmission cost saving; the Original still has lower offshore wind deployment but this is offset somewhat by earlier onshore reinforcements
    - Note that the Original has more CCGT towards 2030. This leads to a large saving in fuel costs that outweighs the increase in generation capital and operational expenditure.
    - The Original has lower power prices, due to a higher capacity margin, and also has lower capacity payments.
    - The Original has slightly higher low carbon support. This may be the result of lower reference power prices, rather than a difference in the strike prices of the capacity built

<u>Comparison across results: Original to alternatives</u>

- There is significant similarity across the outcomes for the various models in the pre-2020 period. They all show a benefit of some sort (albeit small in the case of Diversity 2 and 3). Transmission reinforcements are broadly similar across all alternatives and the Original.
- After 2020 the results are more varied. Diversity 1 shows the greatest decrease in power sector costs. However this option has lower renewables in 2030 which is having an effect in reducing costs.
- All options show reduced wholesale costs due to higher capacity margins than the Original.
- Original and Original 50% HVDC are virtually identical with little impact on HVDC transmission investments.
- Diversity 1 and Diversity 2 tariffs show an increase in not-shared year round elements from 2020 onwards. This significantly increases the locational elements of these tariffs, particularly for lower load factor generation.

NPV 2011-2020 (£m real 2012)		Original	HVDC (50% Option)	Diversity 1	Diversity 2	Diversity 3
Benefit relative to Status Quo						
Power sector costs	Generation costs	958	952	931	349	223
	Transmission costs	137	135	143	73	5
	Constraint costs	-40	-41	-34	-29	-32
	Carbon costs	-104	-102	-116	-45	-18
	Decrease in power sector costs	**950**	**943**	**924**	**348**	**178**
Consumer Bills	Wholesale costs (inc. capacity payments)	-1729	-1728	-1725	-1382	-1062
	BSUoS	-20	-21	-17	-15	-16
	Transmission losses	-48	-49	-42	-33	-28
	Demand TNUoS charges	135	135	135	78	24
	Low carbon support	892	885	930	359	154
	Decrease in consumer bills	**-770**	**-779**	**-719**	**-992**	**-928**

Table A1.1 – Comparison of Benefits Relative to Status Quo in period 2011-2020

NPV 2021-2030 (£m real 2012)		Original	HVDC (50% Option)	Diversity 1	Diversity 2	Diversity 3
Benefit relative to Status Quo						
Power sector costs	Generation costs	-84	-116	517	-579	-1670
	Transmission costs	214	205	407	236	86
	Constraint costs	33	37	43	-3	-9
	Carbon costs	257	274	58	304	249
	Decrease in power sector costs	**420**	**399**	**1025**	**-41**	**-1345**
Consumer Bills	Wholesale costs (inc. capacity payments)	4194	4226	3517	2895	7571
	BSUoS	17	18	21	-1	-5
	Transmission losses	-42	-49	32	28	53
	Demand TNUoS charges	187	186	274	152	24
	Low carbon support	-397	-454	666	-464	-2026
	Decrease in consumer bills	**3958**	**3927**	**4510**	**2609**	**5617**

Table A1.2 – Comparison of Benefits Relative to Status Quo in period 2021-2030

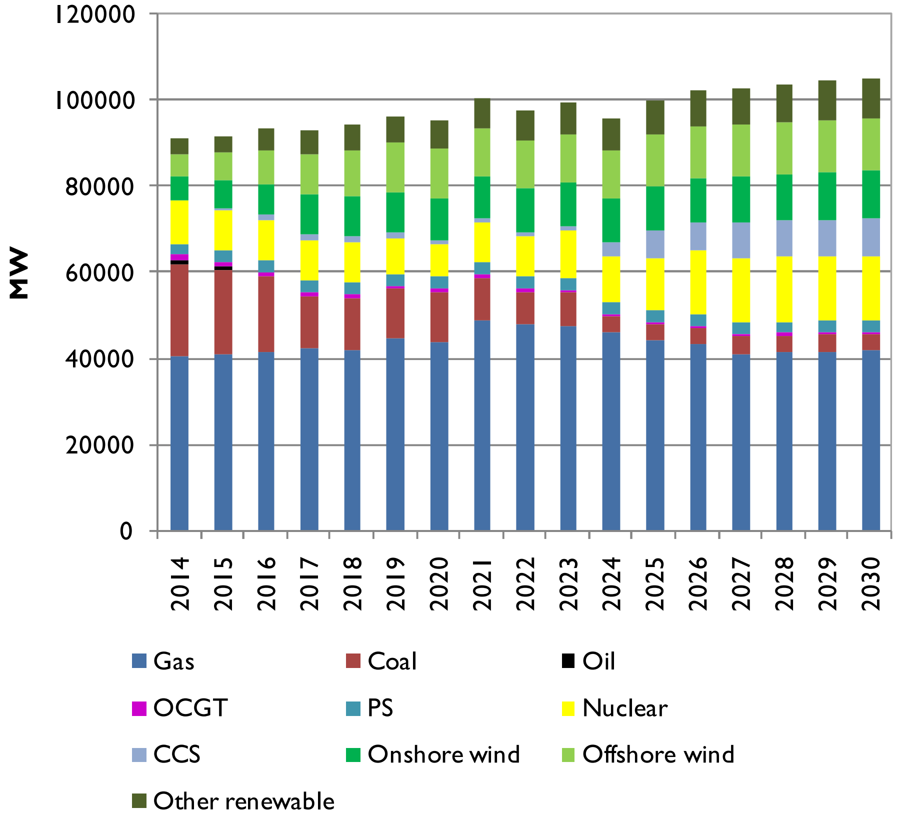

Figure A 1.1 - Generation Mix (includes regional breakdown): Status Quo

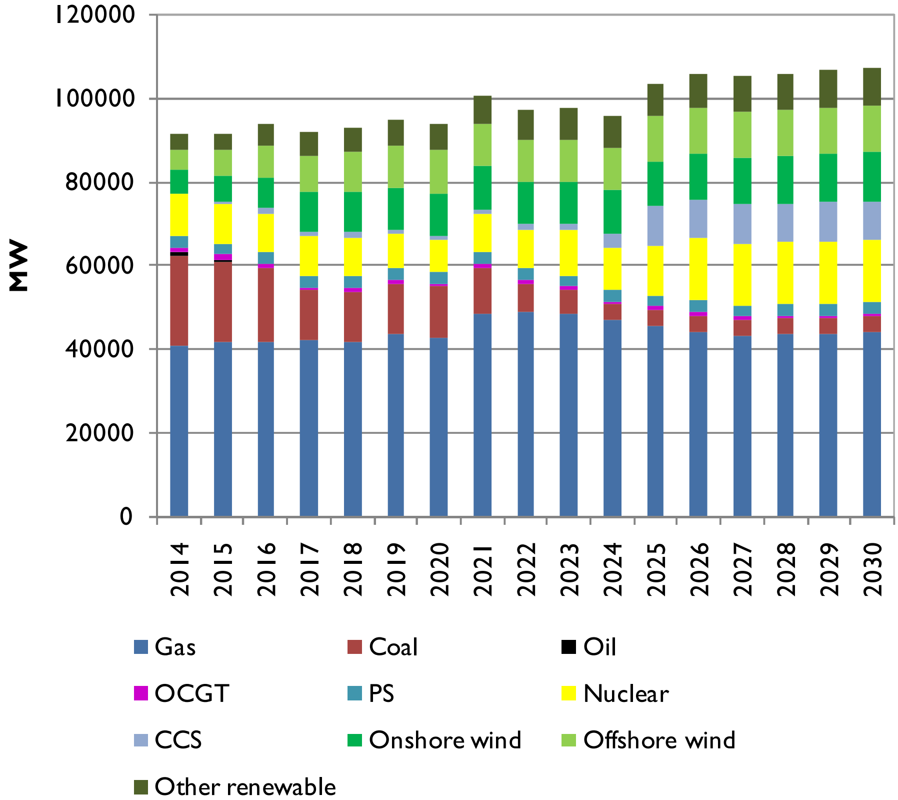

Figure A 1.2 - Generation Mix (includes regional breakdown): Original

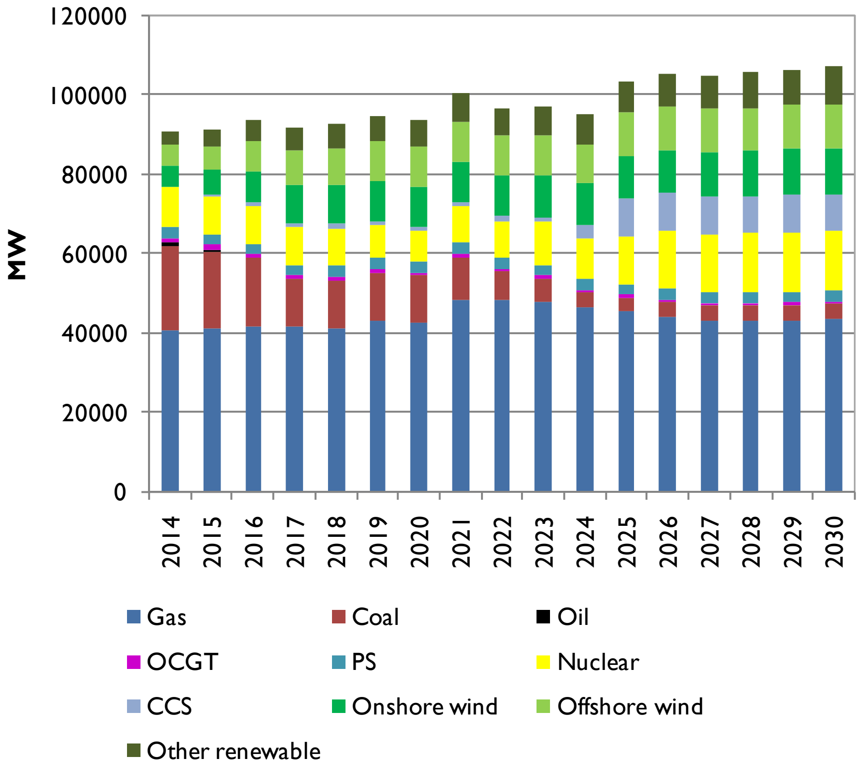

Figure A 1.3 - Generation mix (includes regional breakdown): Original 50% HVDC Converters

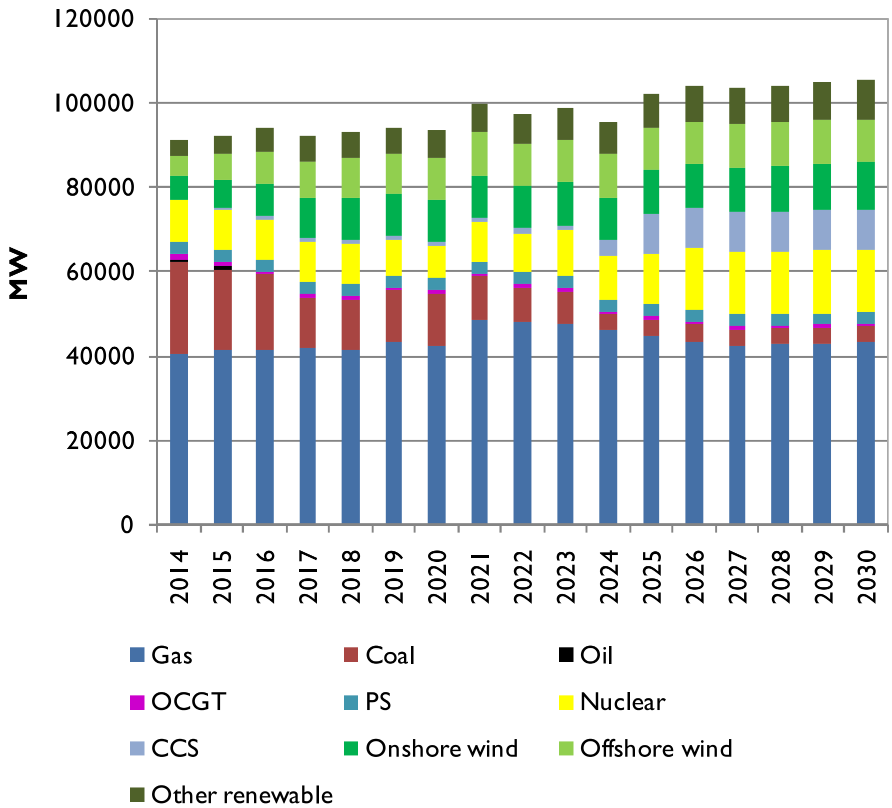

Figure A 1.4 - Generation mix (includes regional breakdown): Diversity 1

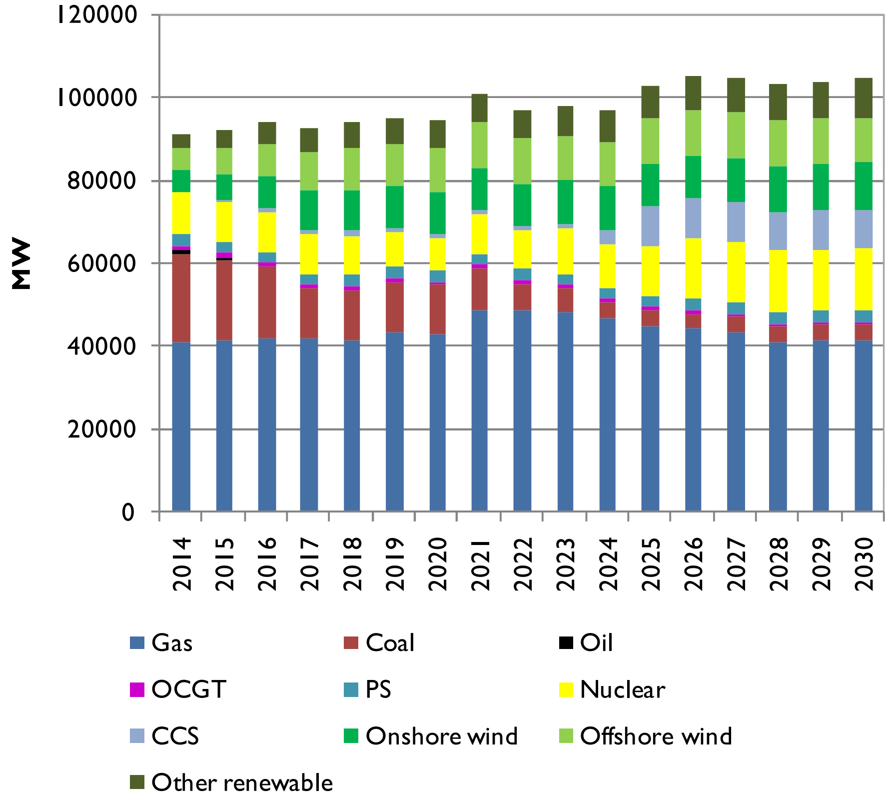

Figure A 1.5 - Generation mix (includes regional breakdown): Diversity 2

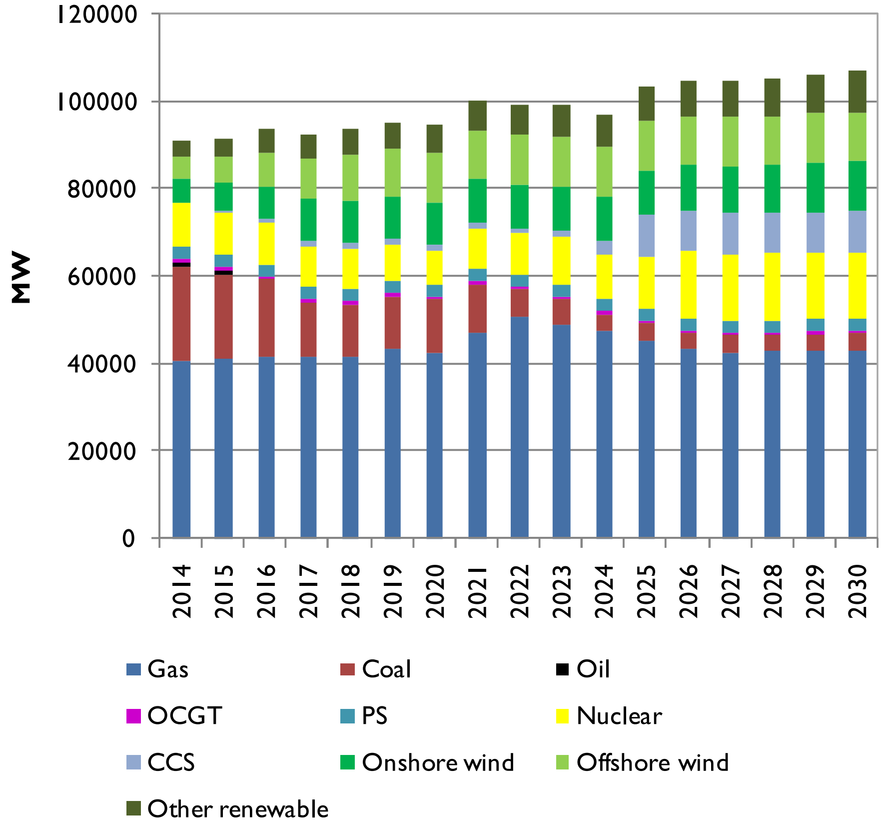

Figure A 1.6 - Generation mix (includes regional breakdown): Diversity 3

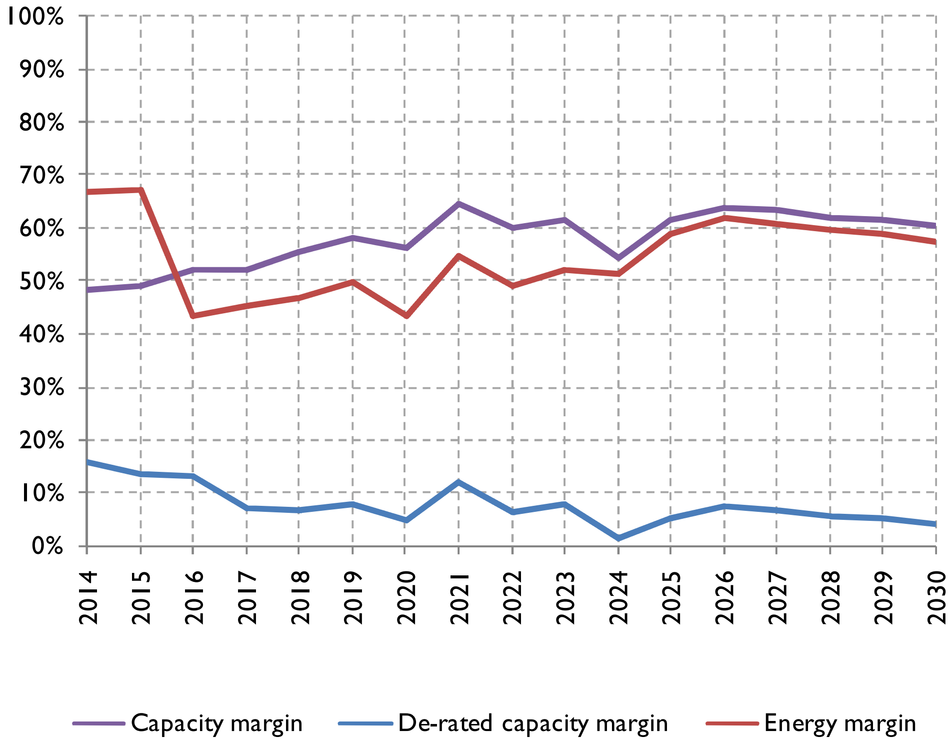

Figure A 1.7 - Capacity margins: Status Quo

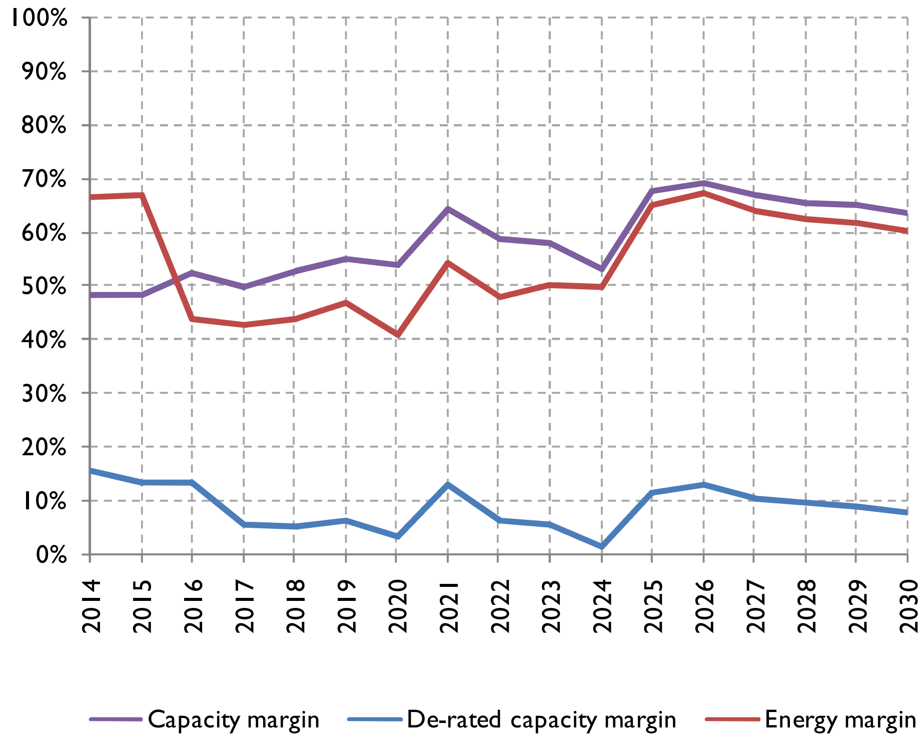

Figure A 1.8 - Capacity margins: Original

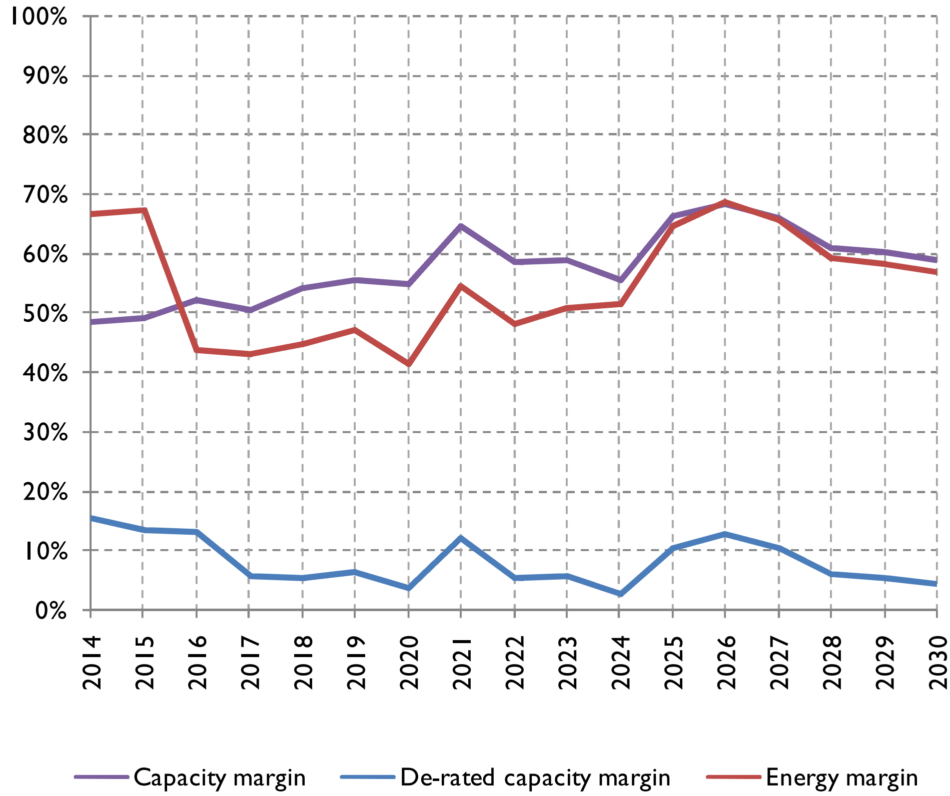

Figure A 1.9 - Capacity margins: Original 50% HVDC Converters

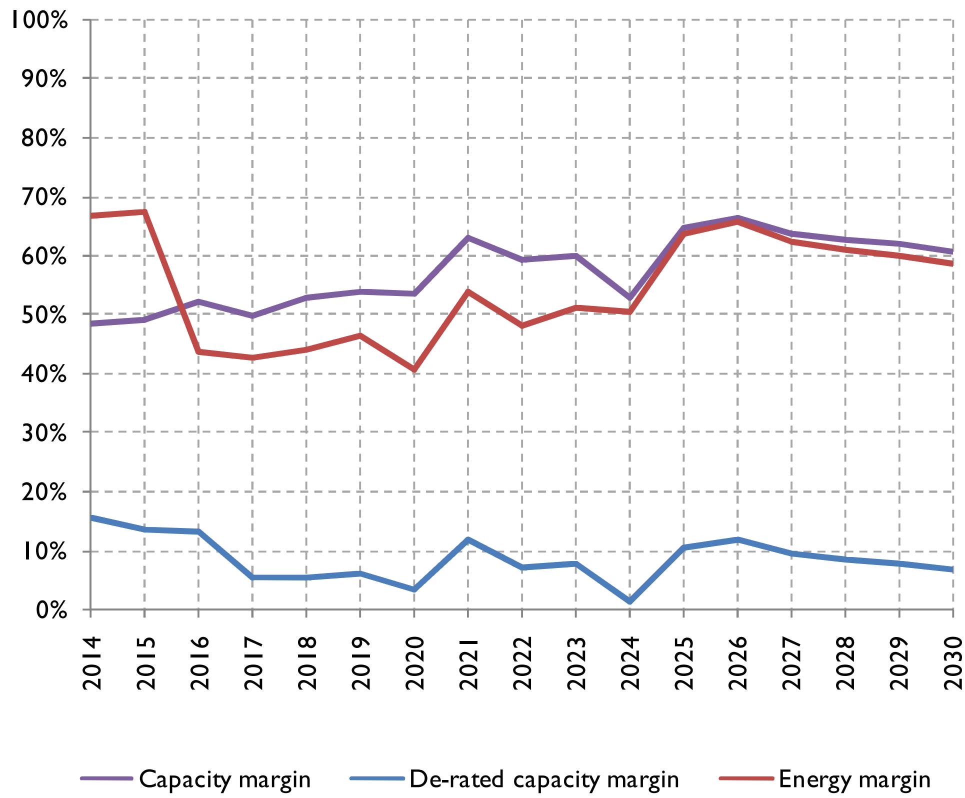

Figure A 1.10 - Capacity margins: Diversity 1

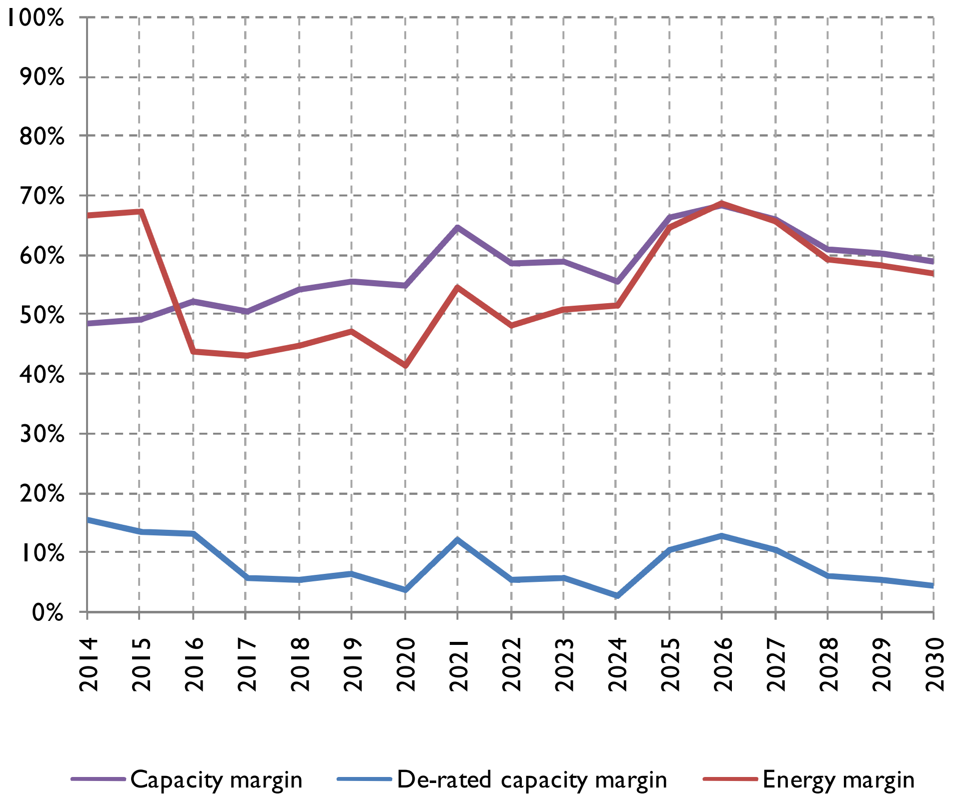

Figure A 1.11 -Capacity margins: Diversity 2

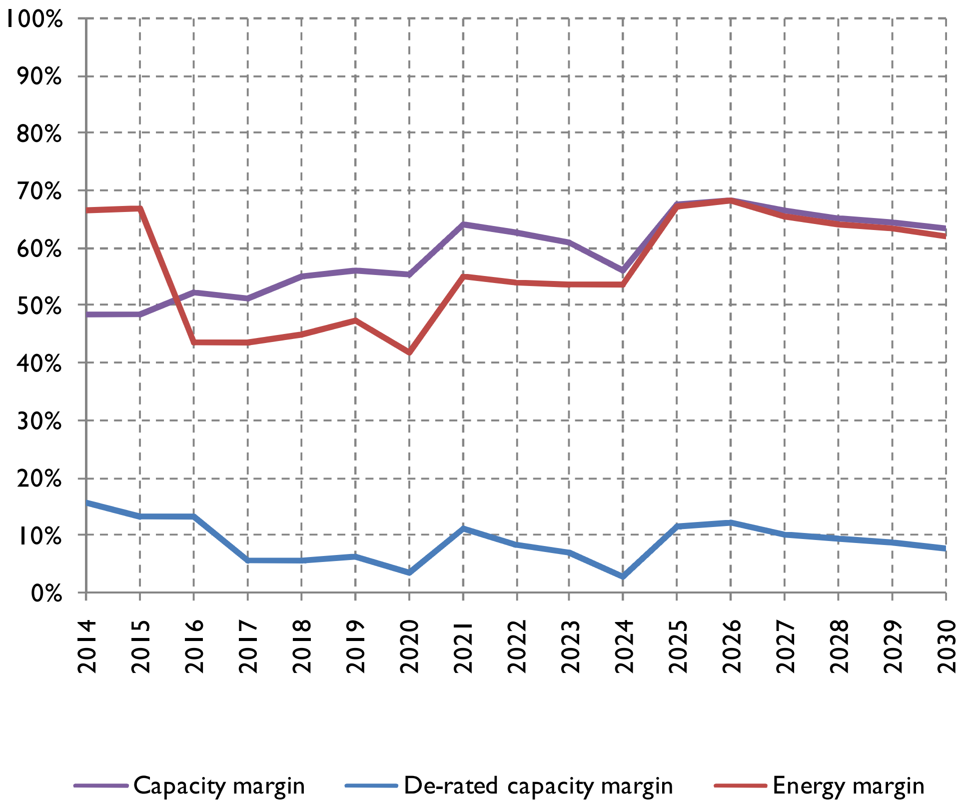

Figure A 1.12 - Capacity margins: Diversity 3

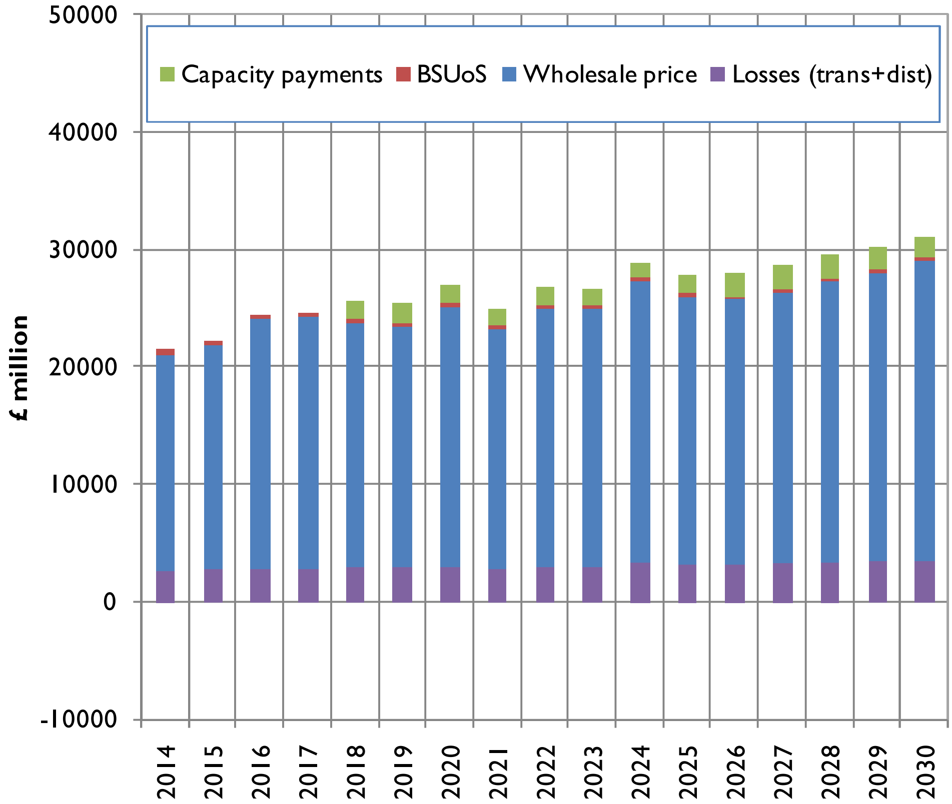

Figure A 1.13 - Wholesale costs: Status Quo

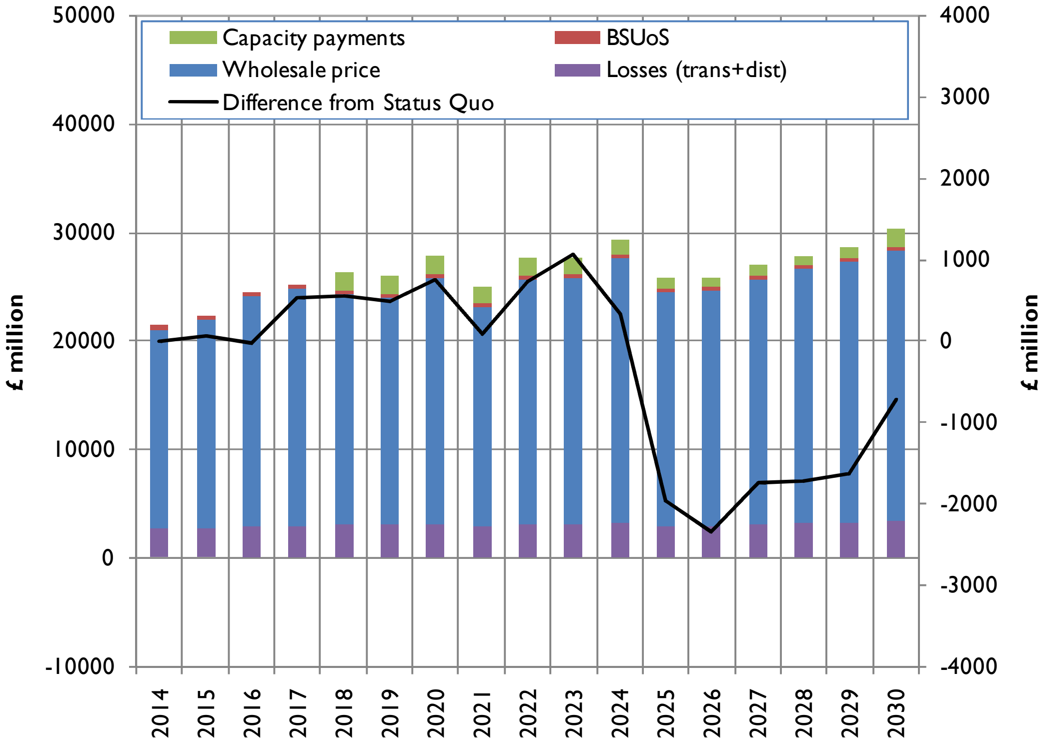

Figure A 1.14 - Wholesale costs: Original

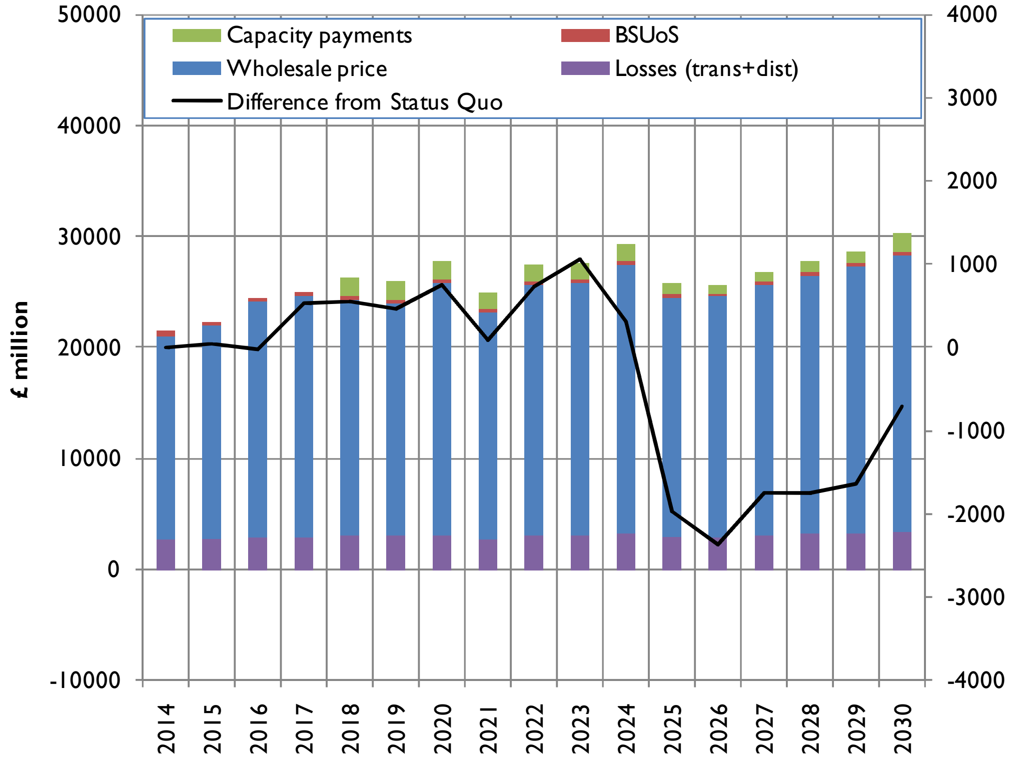

Figure A 1.15 - Wholesale costs: Original 50% HVDC Converters

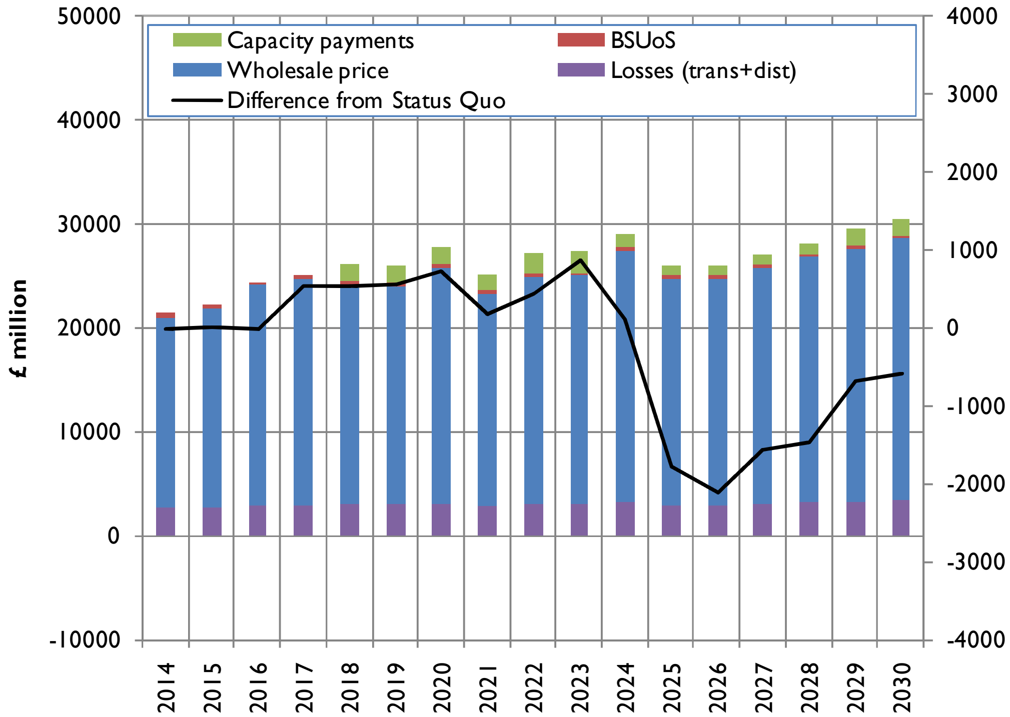

Figure A 1.16 - Wholesale costs: Diversity 1

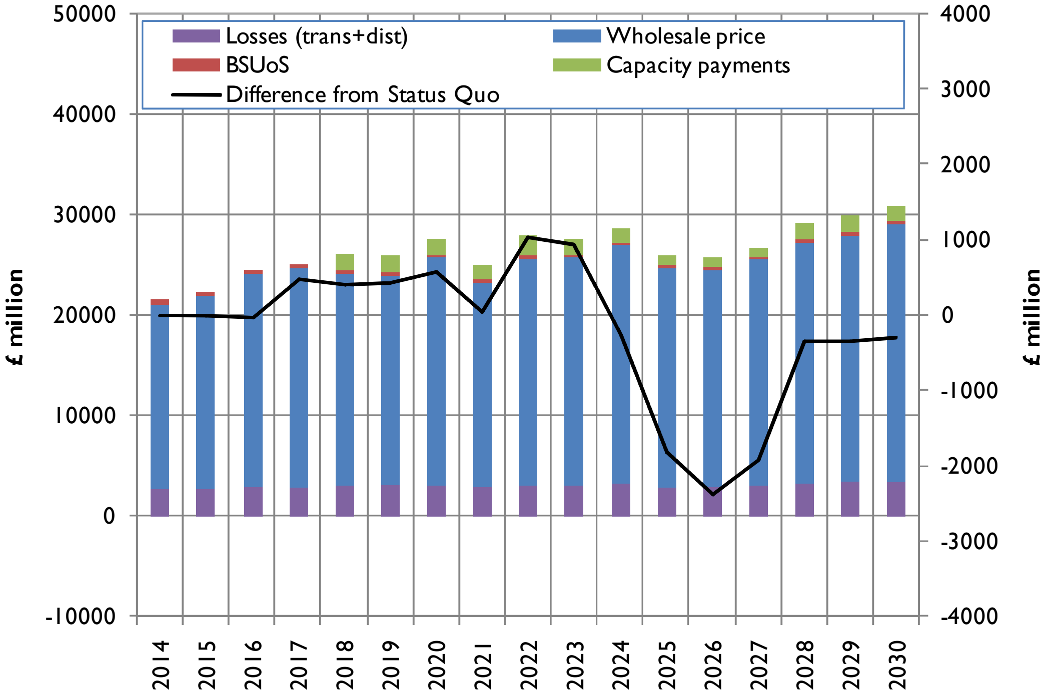

Figure A 1.17 - Wholesale costs: Diversity 2

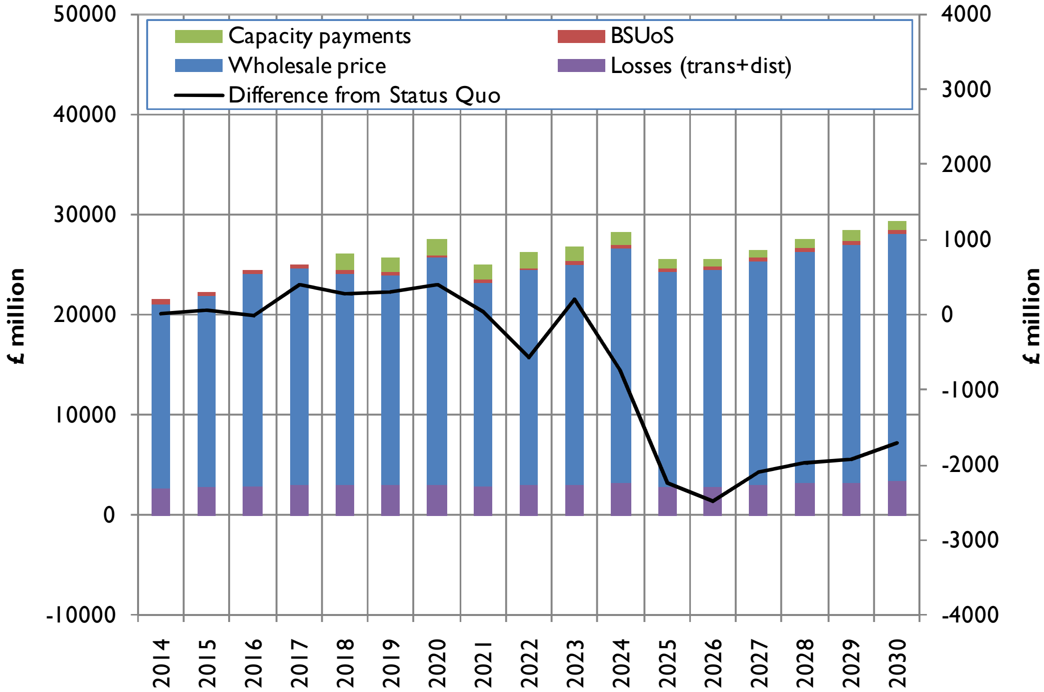

Figure A 1.18 - Wholesale costs: Diversity 3

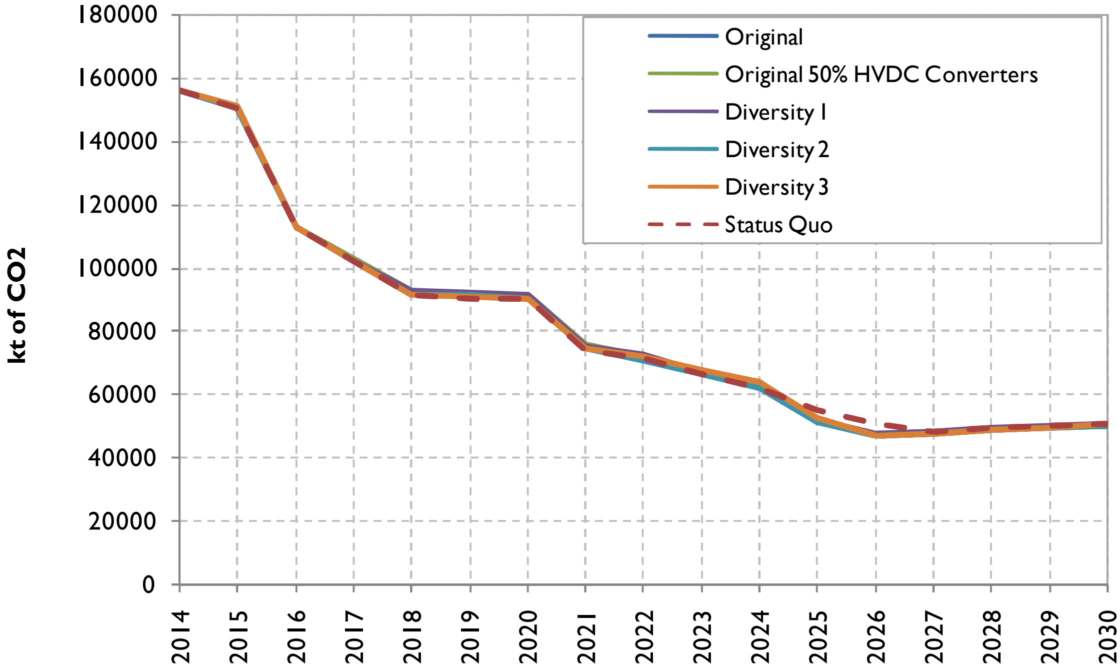

Figure A 1.19 - CO_2 Emissions

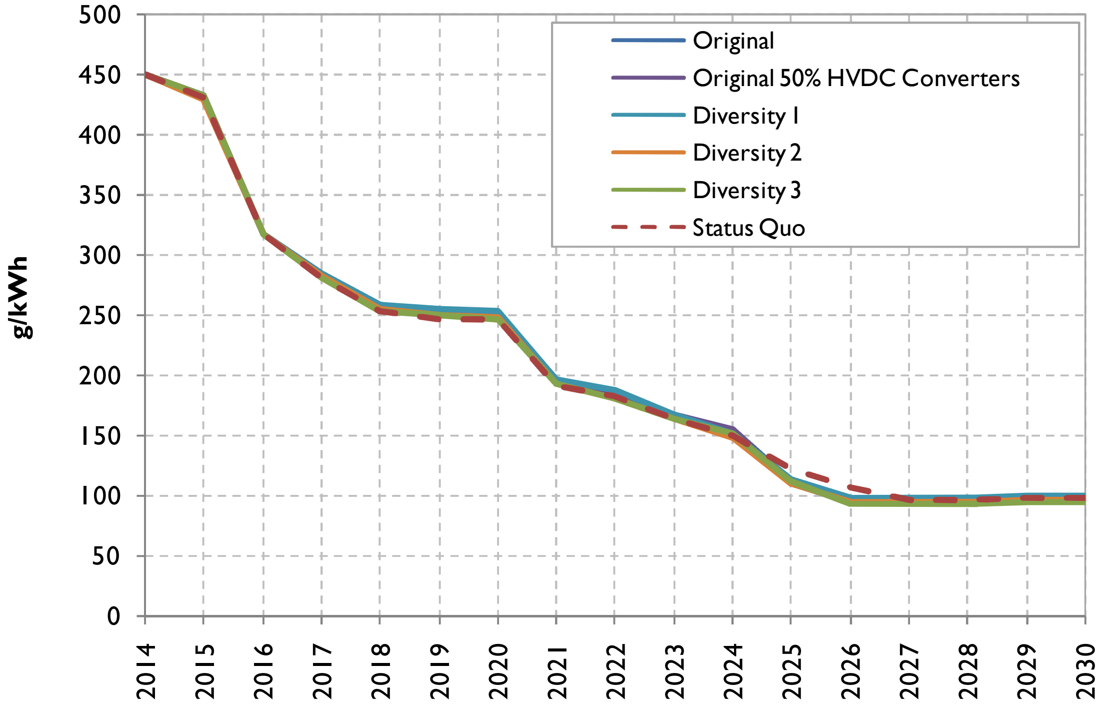

Figure A 1.20 - Carbon Intensity

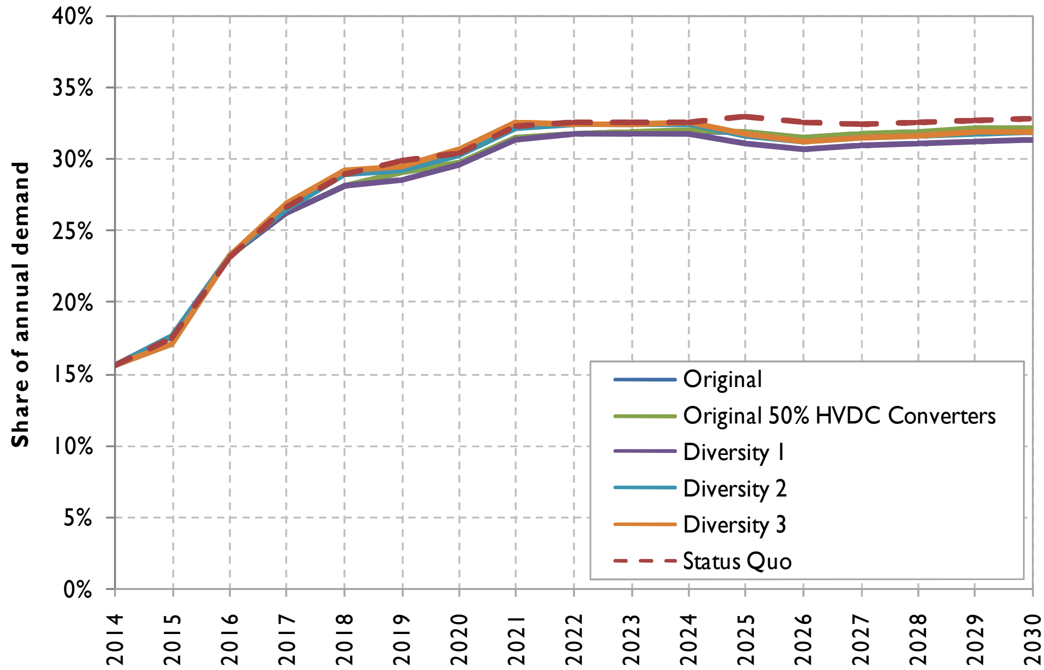

Figure A 1.21 - Renewable generation

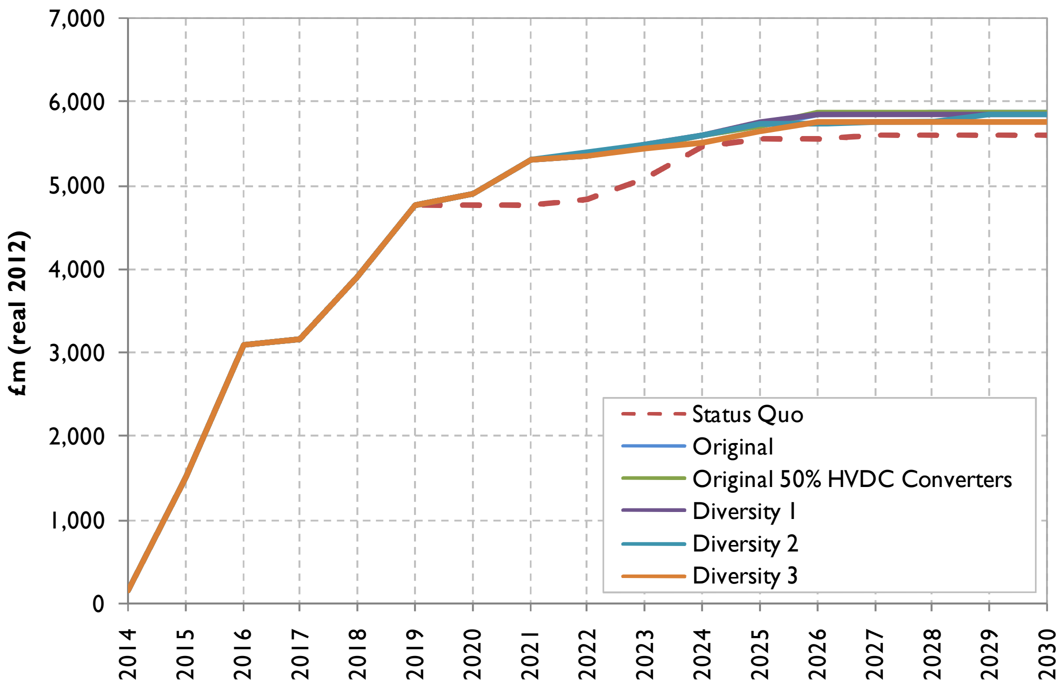

Figure A 1.22 - Transmission investment

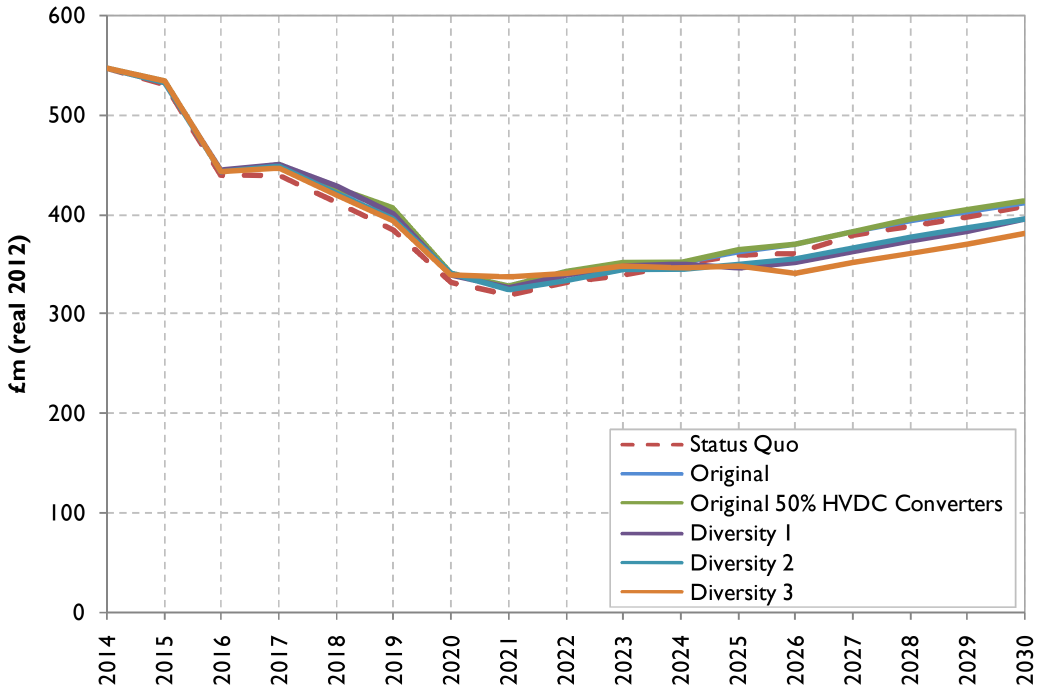

Figure A 1.23 - Transmission losses

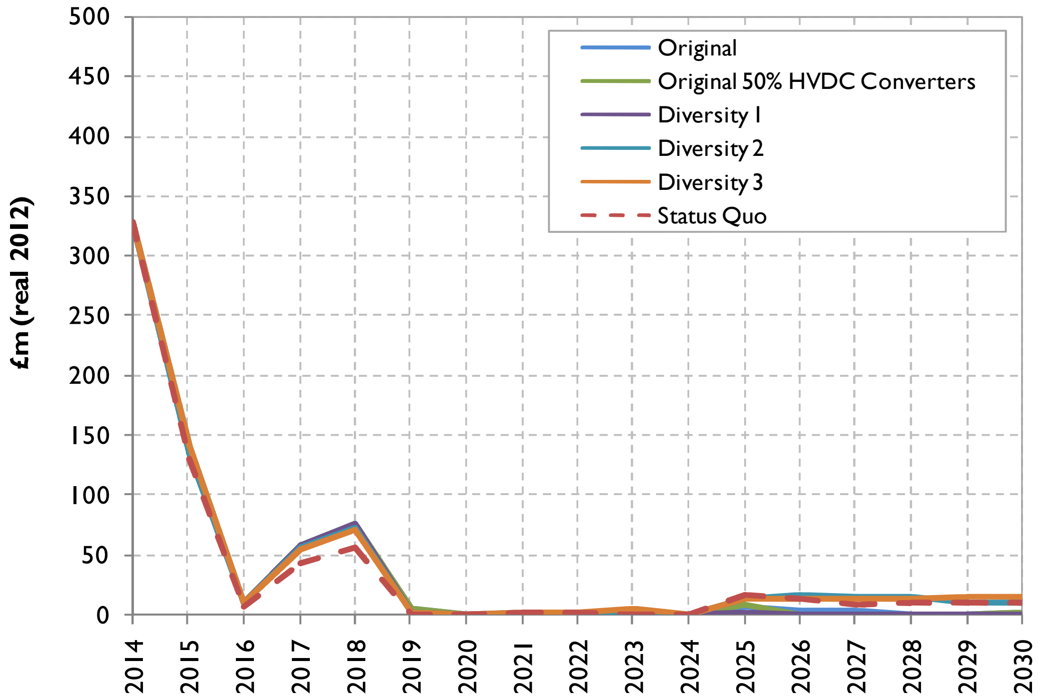

Figure A 1.24 - Constraint costs

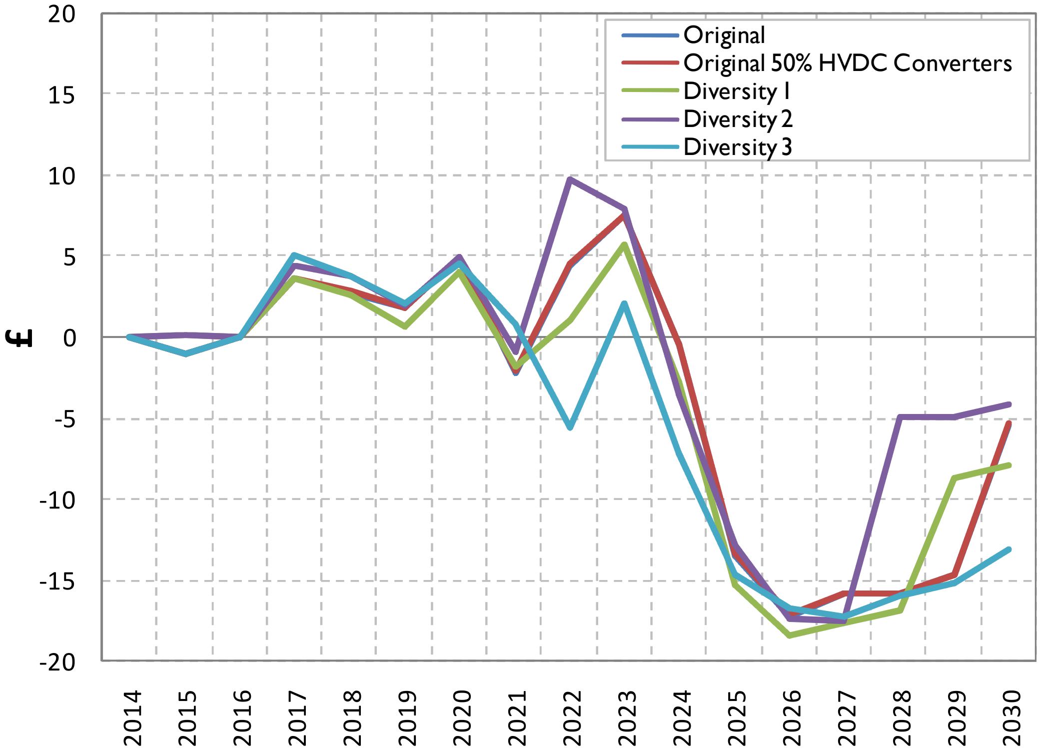

Figure A 1.25 - Change in average consumer bill

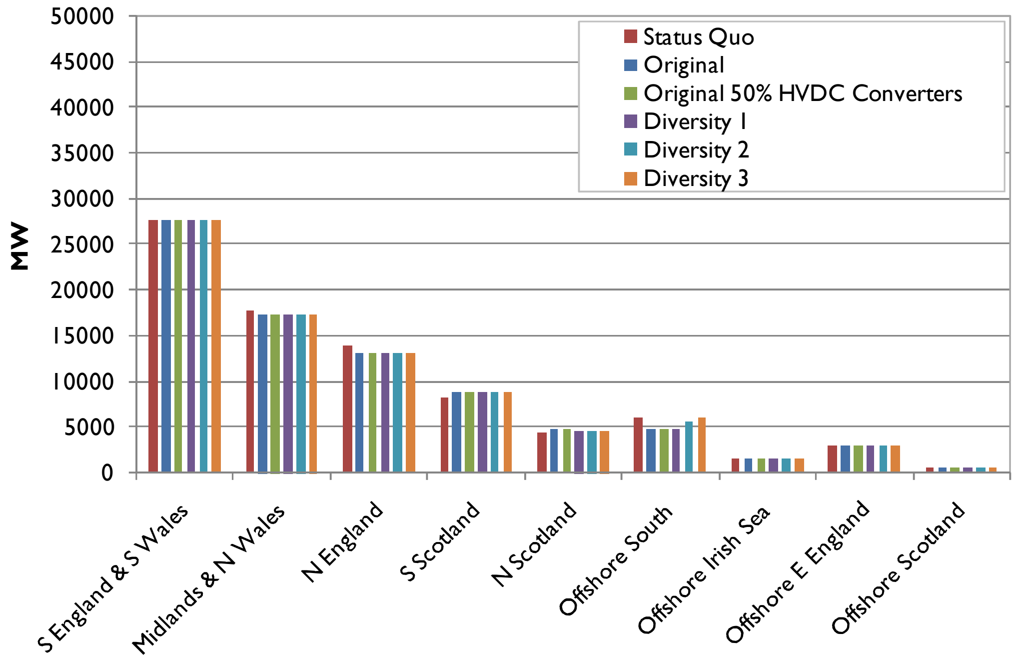

Figure A 1.26 - Capacity by Zone: 2020

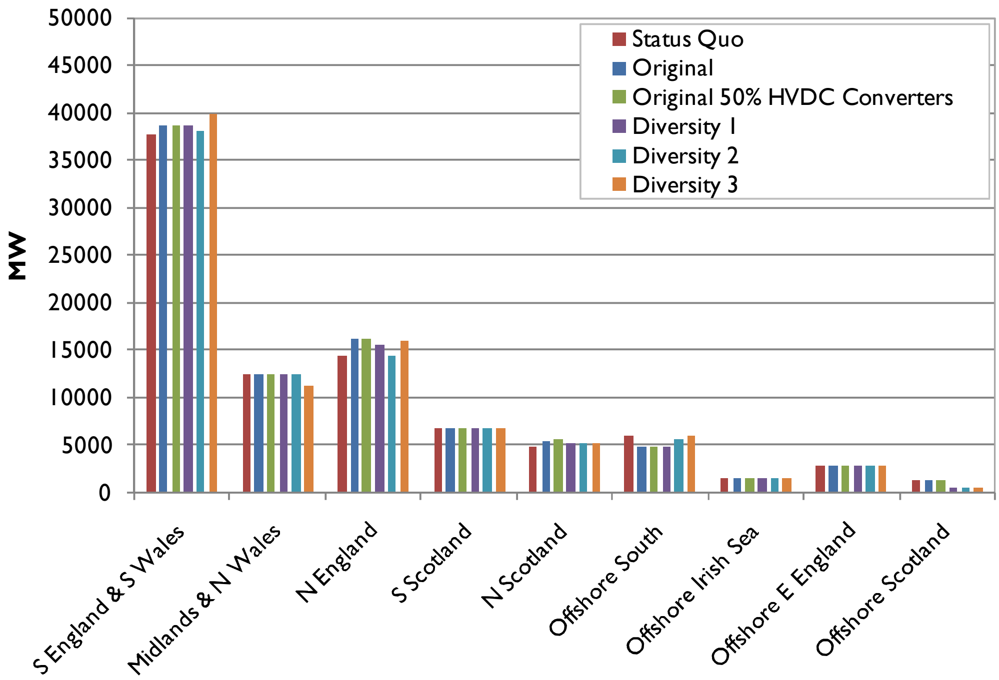

Figure A 1.27 - Capacity by Zone: 2030

Table A1.3 – CfD Strike Price - Status Quo

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	95	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	101	101	101
Onshore wind	98	90	89	88	87
Offshore wind	142	123	117	113	109
Wave	350	280	236	216	199
Tidal Stream	336	262	237	217	200
Biomass regular	120	110	110	110	109

Table A1.4 – CfD Strike Price – Original

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	96	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	102	102	102
Onshore wind	96	89	88	87	86
Offshore wind	141	123	118	114	110
Wave	347	280	235	215	198
Tidal Stream	336	265	240	219	202
Biomass regular	121	112	111	111	111

Table A1.5 – CfD Strike Price - Original 50% HVDC Converters

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	101	96	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	102	102	102
Onshore wind	96	89	88	87	86
Offshore wind	141	123	118	114	110
Wave	347	280	235	215	198
Tidal Stream	336	265	240	219	202
Biomass regular	121	112	111	111	111

Table A1.6 – CfD Strike Price - Diversity 1

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	95	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	102	101	101
Onshore wind	96	87	86	85	84
Offshore wind	140	120	114	110	106
Wave	346	273	230	211	194
Tidal Stream	333	256	232	212	195
Biomass regular	120	108	107	107	107

Table A1.7 – CfD Strike Price - Diversity 2

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	95	93	92
Coal + CCS	137	137	135	135	137
CCGT + CCS	103	102	102	101	101
Onshore wind	96	87	86	85	84
Offshore wind	140	120	114	110	106
Wave	346	273	230	211	194
Tidal Stream	333	256	232	212	195
Biomass regular	119	108	107	107	107

Table A1.8 – CfD Strike Price - Diversity 3

(£/MWh)	2018-2020	2021-2023	2024-2026	2027-2028	2029-2030
Nuclear	104	100	95	93	92
Coal + CCS	137	137	136	135	137
CCGT + CCS	103	102	102	101	101
Onshore wind	97	87	86	86	85
Offshore wind	141	120	114	111	107
Wave	346	273	230	211	194
Tidal Stream	333	256	232	212	196
Biomass regular	119	108	107	107	107

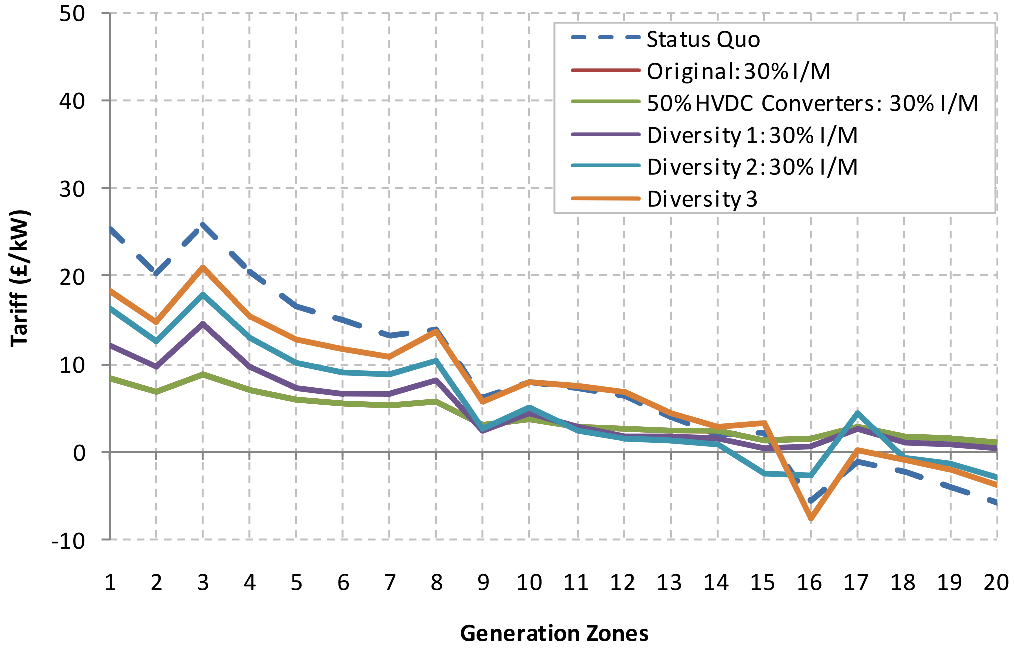

Figure A 1.28 - 2014 illustrative tariffs: Intermittent Generation (30% Annual Load Factor)

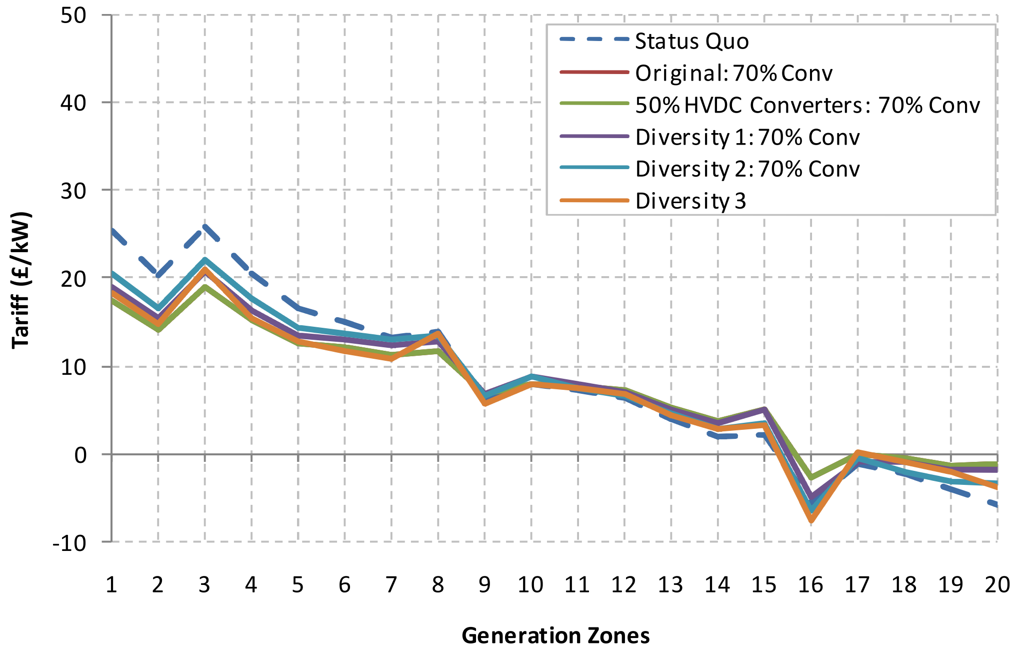

Figure A 1.29 - 2014 illustrative tariffs: Conventional Generation (70% Annual Load Factor)

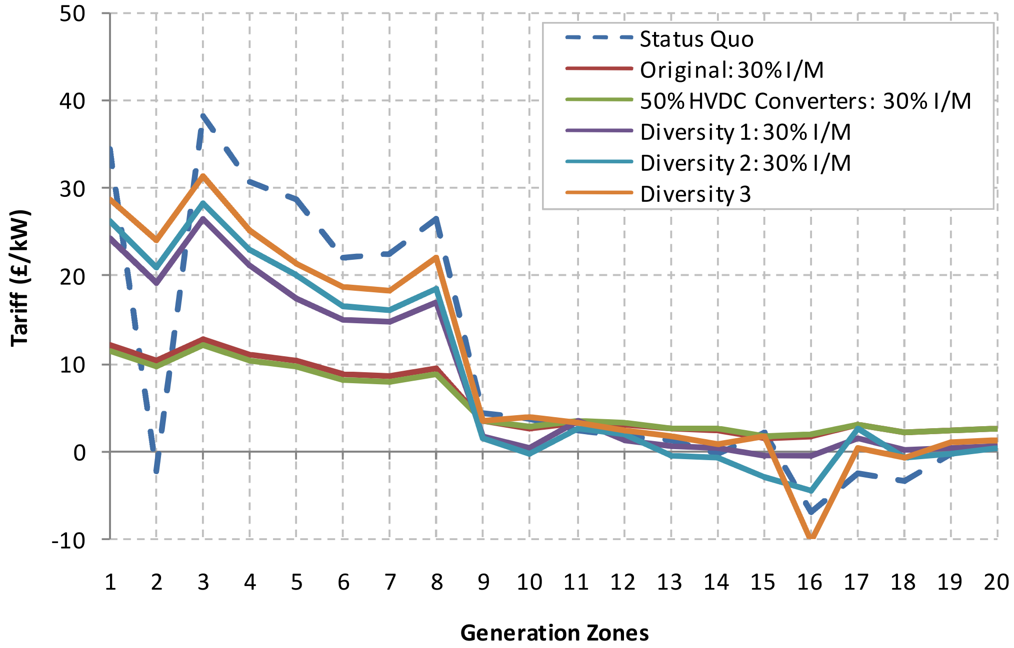

Figure A 1.30 - 2020 illustrative tariffs: Intermittent Generation (30% Annual Load Factor)

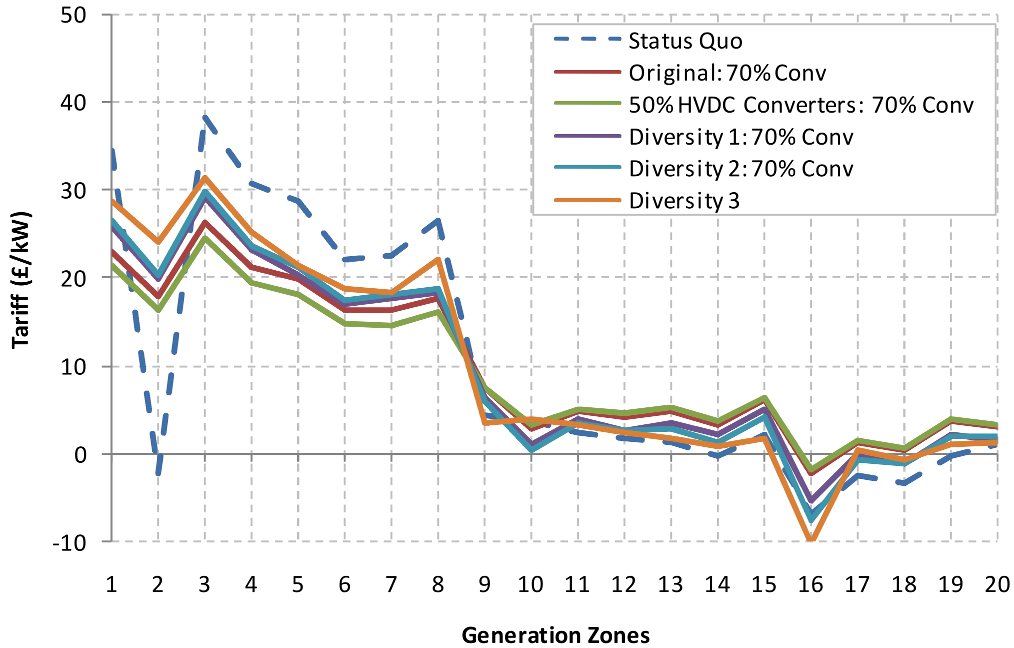

Figure A 1.31 - 2020 illustrative tariffs: Conventional Generation (70% Annual Load Factor)

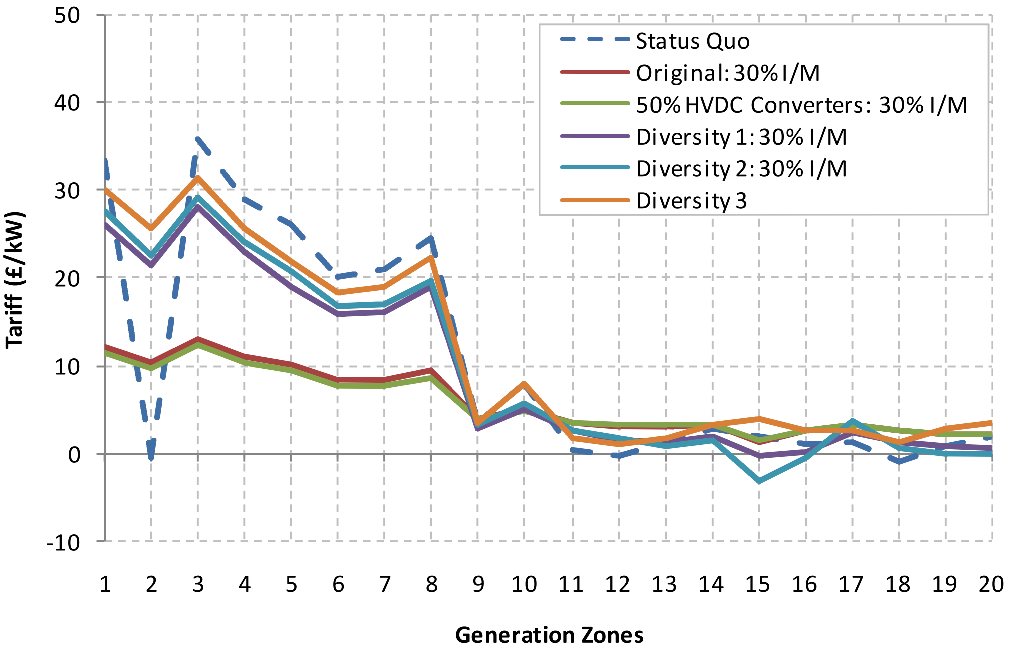

Figure A 1.32 - 2030 illustrative tariffs: Intermittent Generation (30% Annual Load Factor)

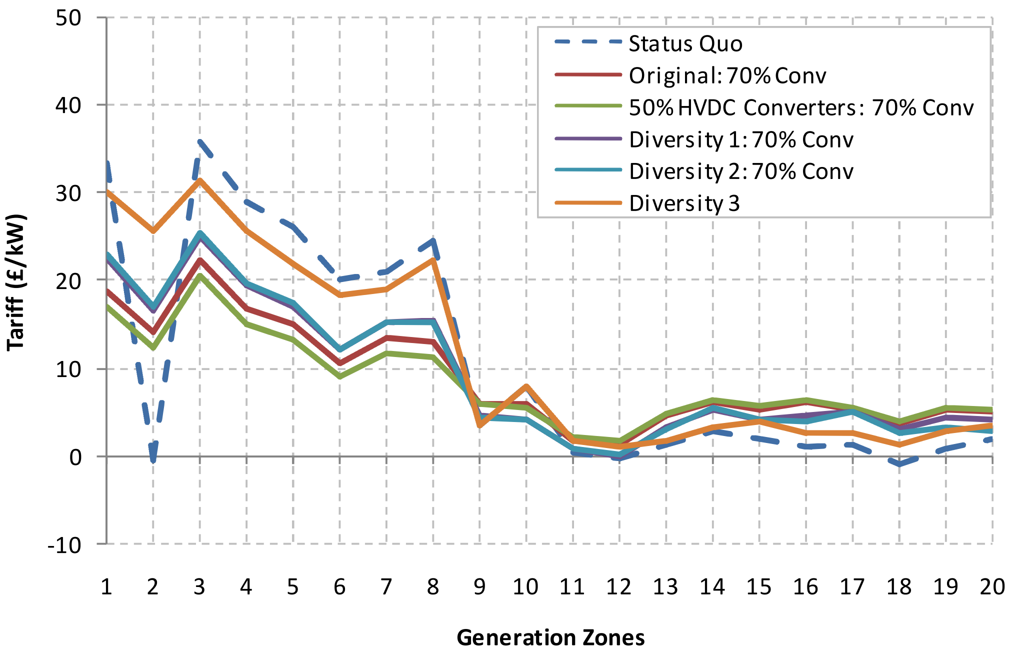

Figure A 1.33 - 2030 illustrative tariffs: Conventional Generation (70% Annual Load Factor)

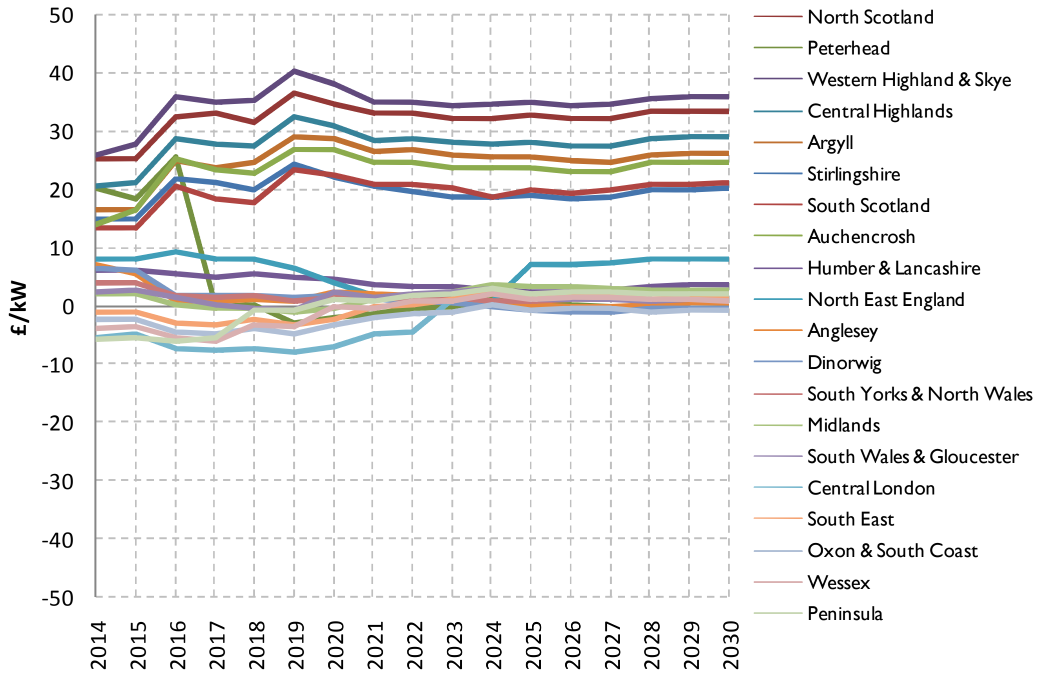

Figure A 1.34 - Illustrative wider generation tariffs by zone: Status Quo

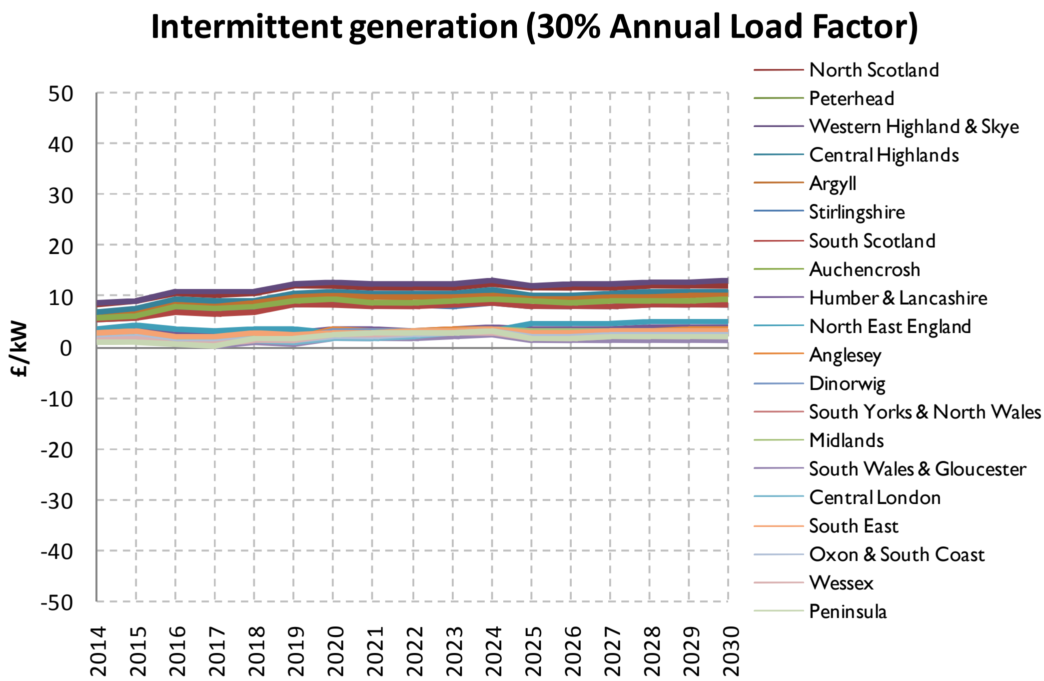

Figure A 1.35 - Illustrative wider generation tariffs by zone: Original proposal

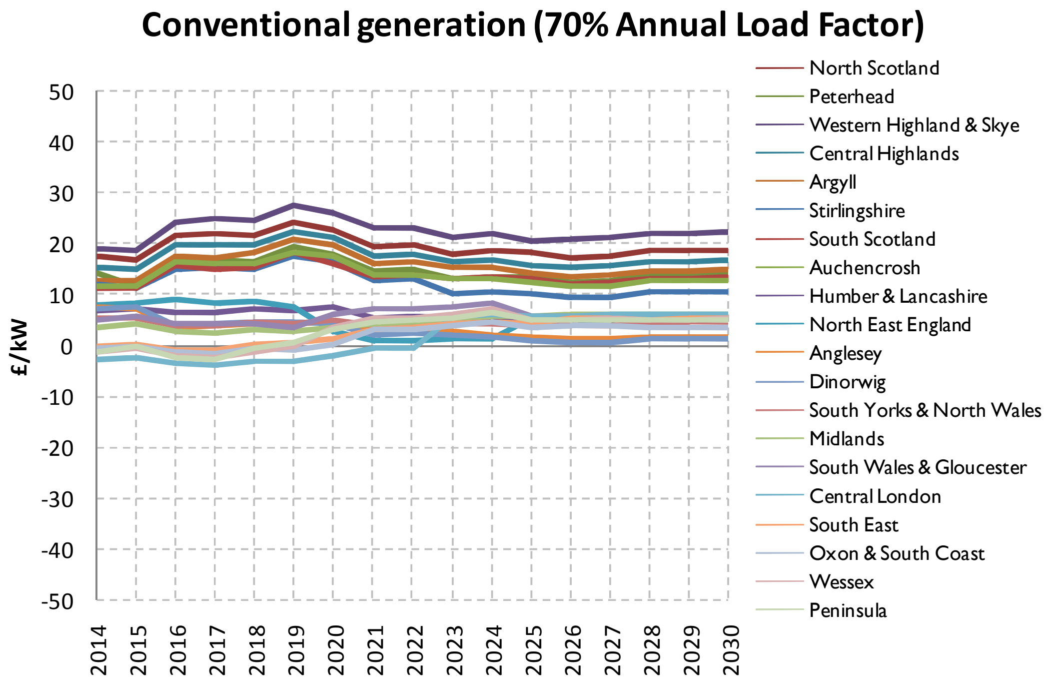

Figure A 1.36 - Illustrative wider generation tariffs by zone: Original proposal

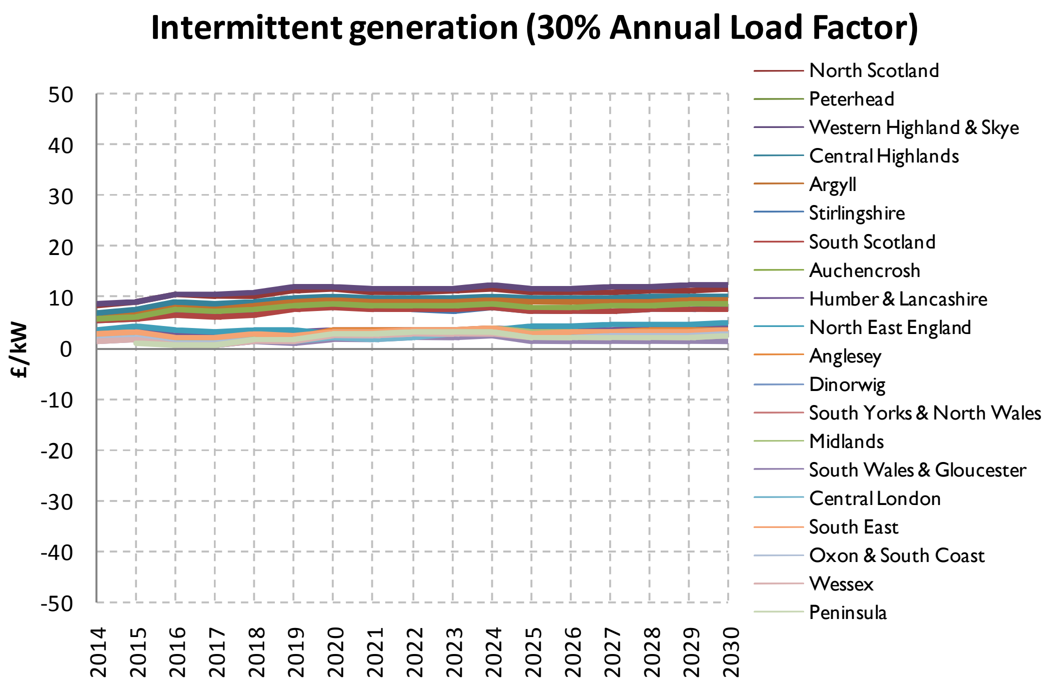

Figure A 1.37 - Illustrative wider generation tariffs by zone: Original 50% HVDC Converters

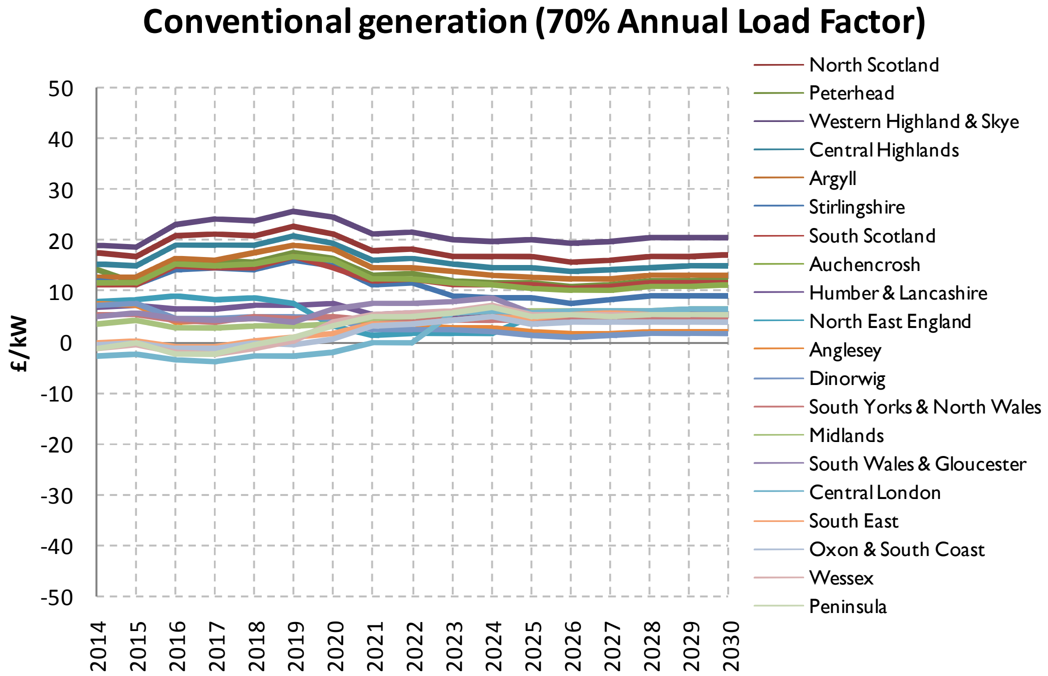

Figure A 1.38 - Illustrative wider generation tariffs by zone: Original 50% HVDC Converters

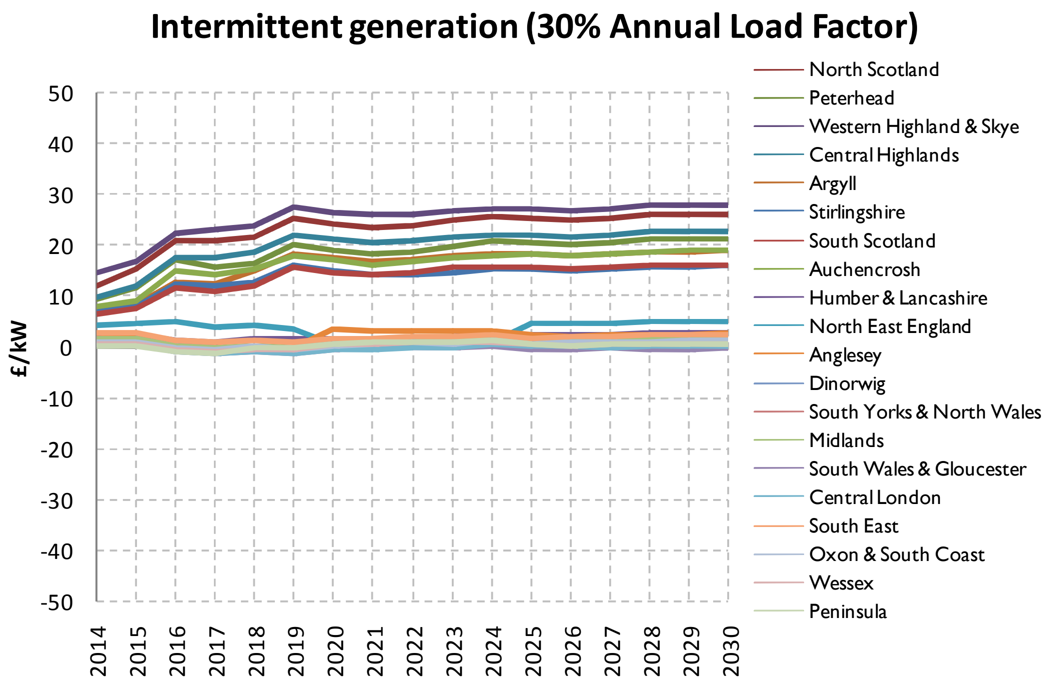

Figure A 1.39 - Illustrative wider generation tariffs by zone: Diversity 1

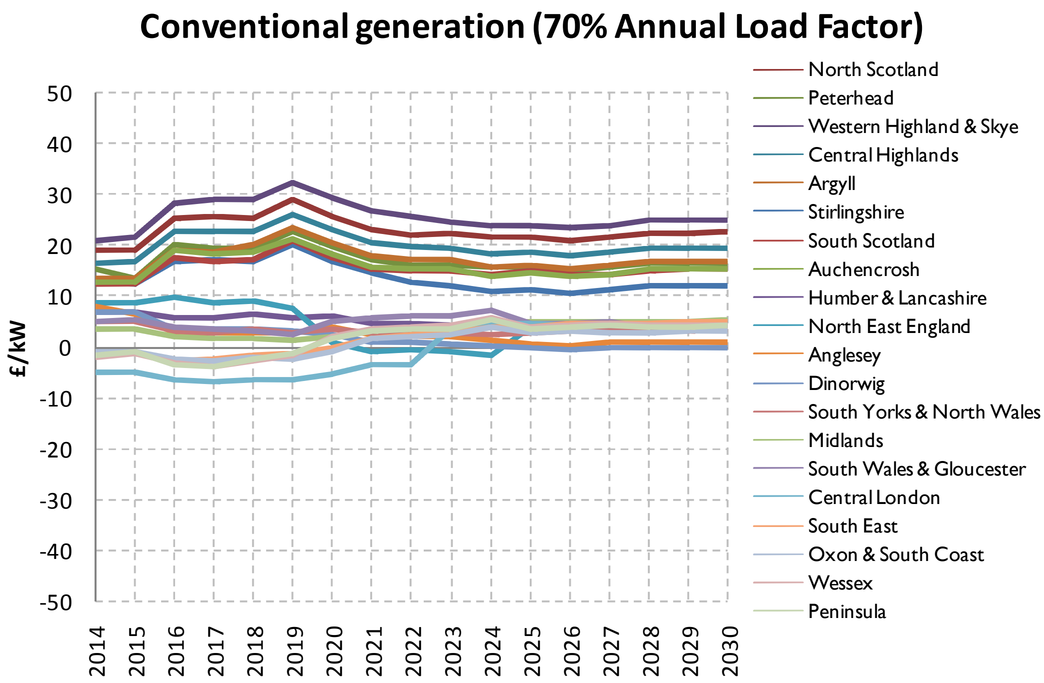

Figure A 1.40 - Illustrative wider generation tariffs by zone: Diversity 1

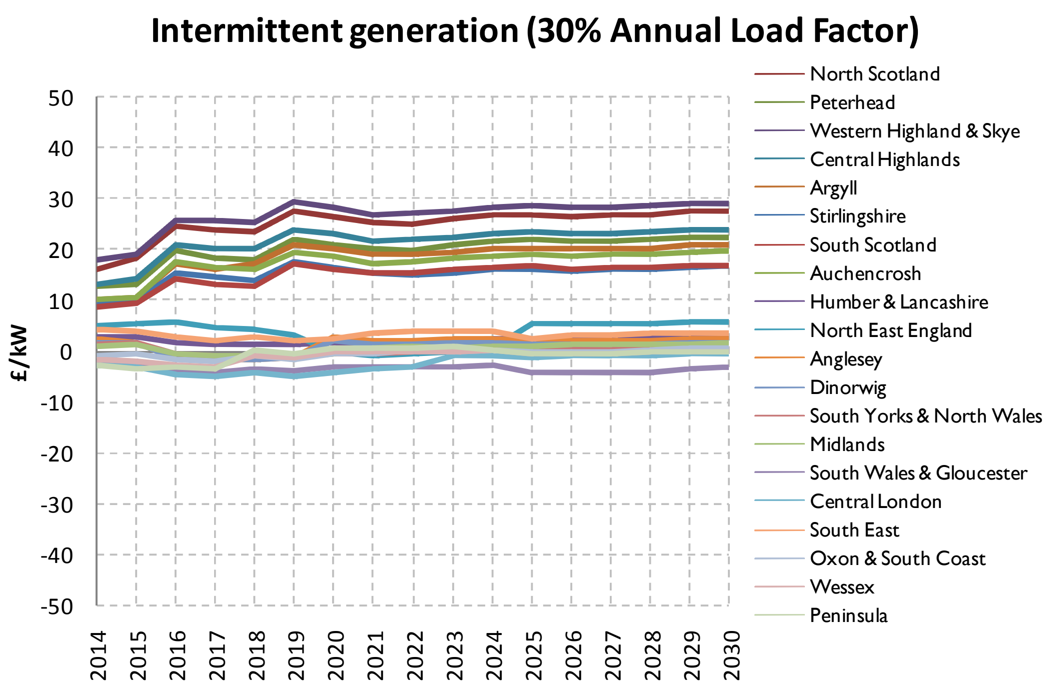

Figure A 1.41 - Illustrative wider generation tariffs by zone: Diversity 2

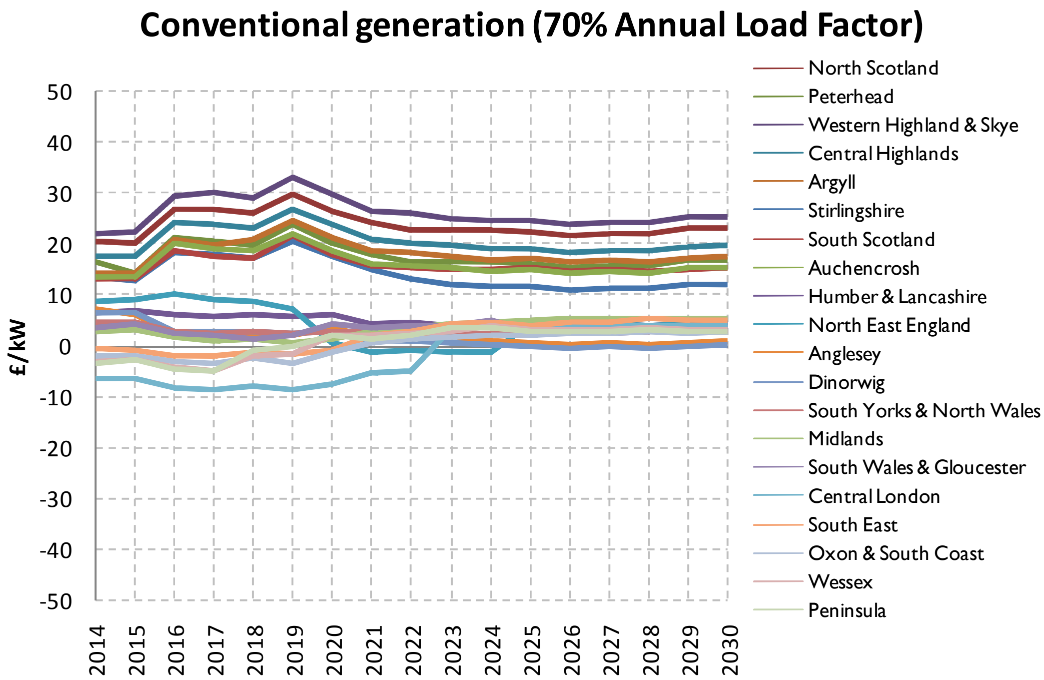

Figure A 1.42 - Illustrative wider generation tariffs by zone: Diversity 2

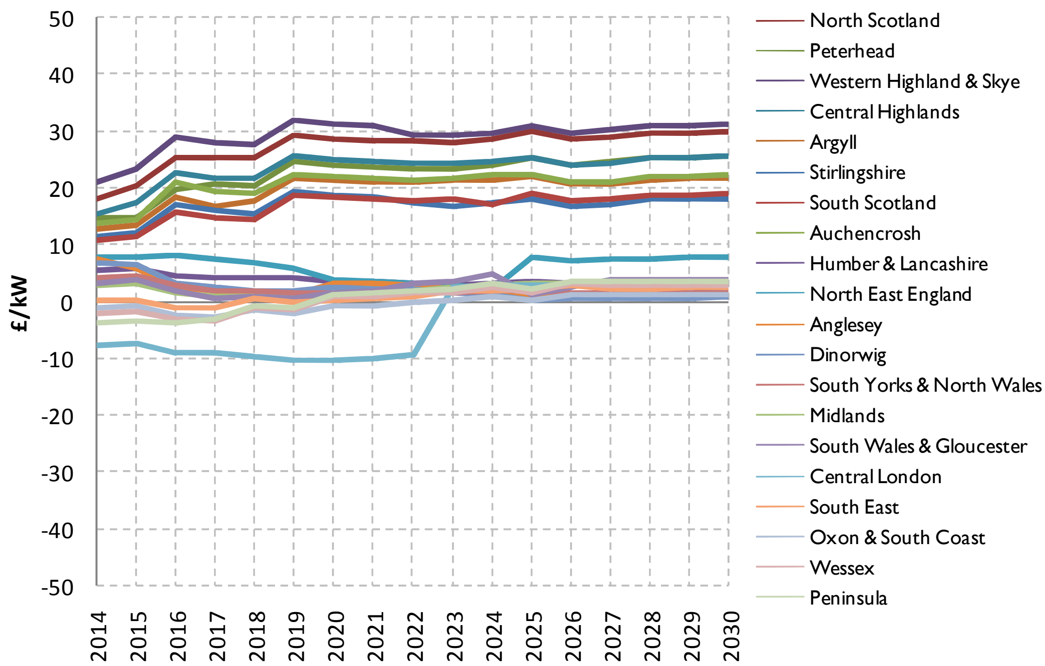

Figure A 1.43 - Illustrative wider generation tariffs by zone: Diversity 3

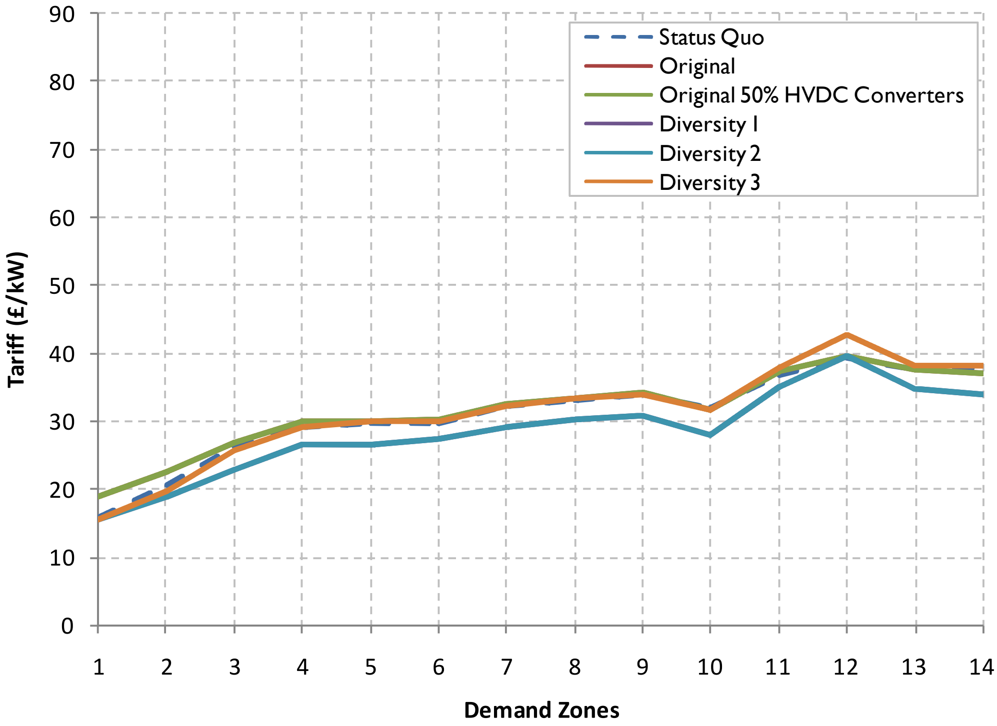

Figure A 1.44 - 2014 illustrative HH Demand tariffs

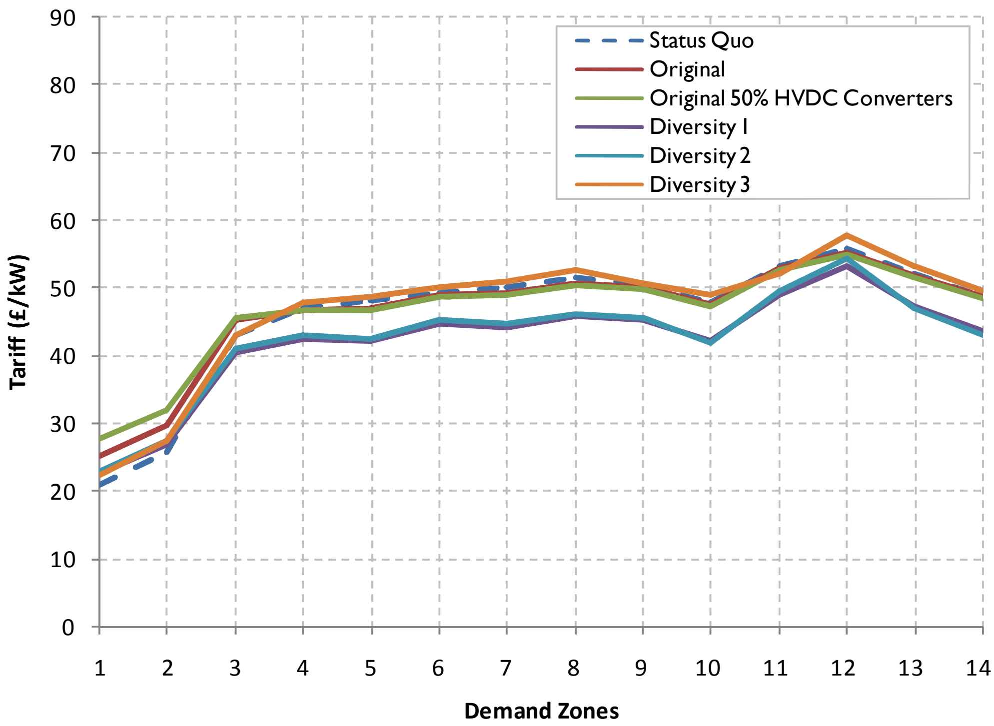

Figure A 1.45 - 2020 illustrative HH Demand tariffs

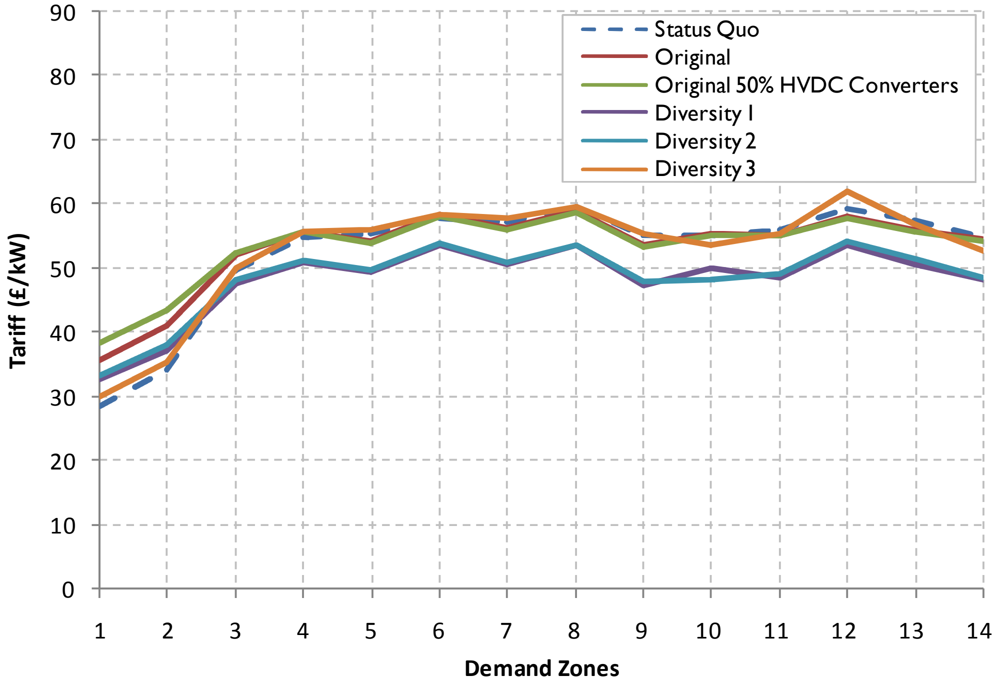

Figure A 1.46 - 2030 illustrative HH Demand tariffs

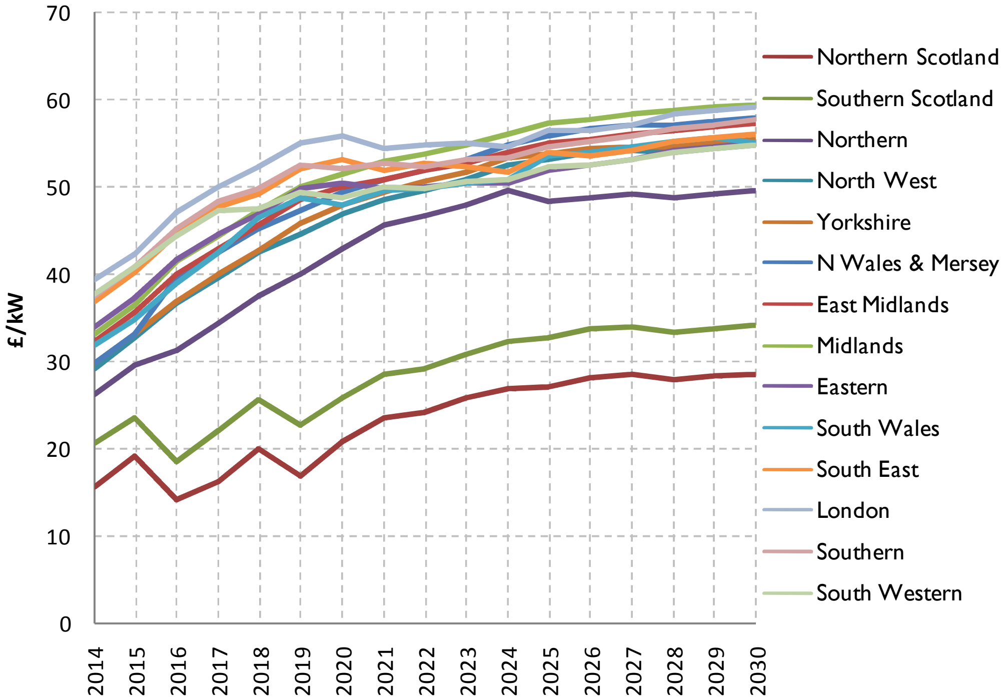

Figure A 1.47 - Illustrative HH Demand tariffs by zone: Status Quo

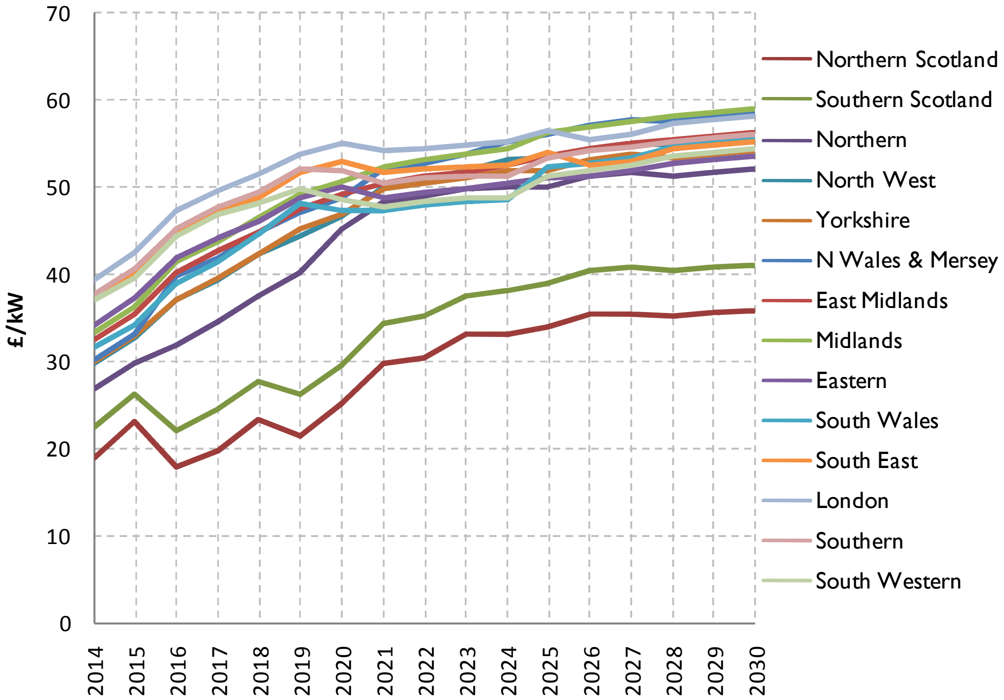

Figure A 1.48 - Illustrative HH Demand tariffs by zone: Original proposal

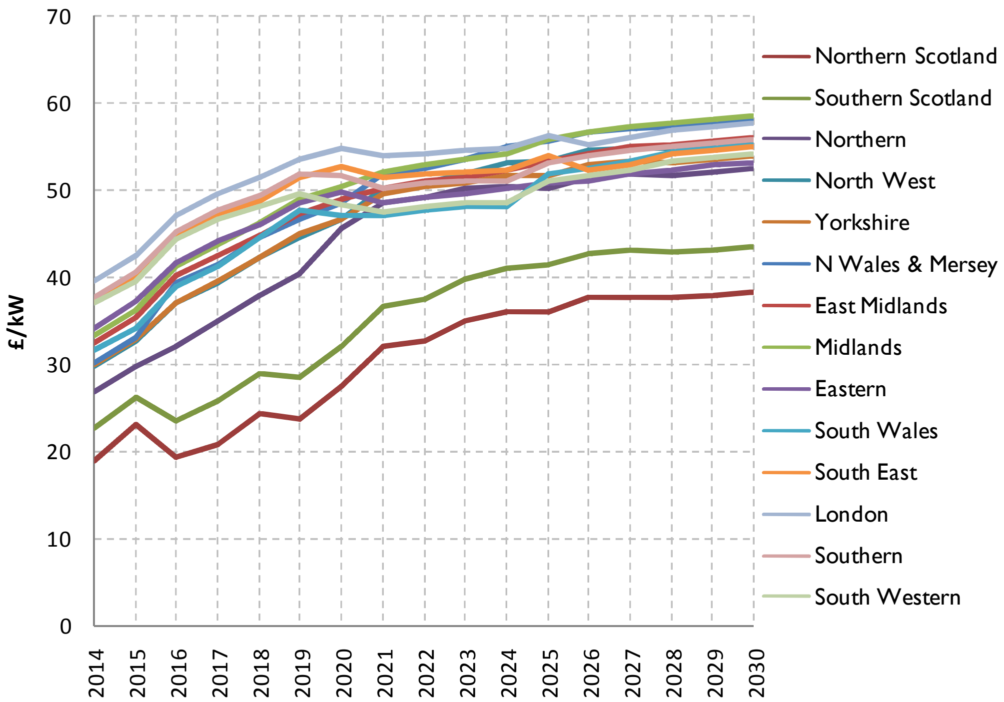

Figure A 1.49 - Illustrative HH Demand tariffs by zone: Original 50% HVDC Converters

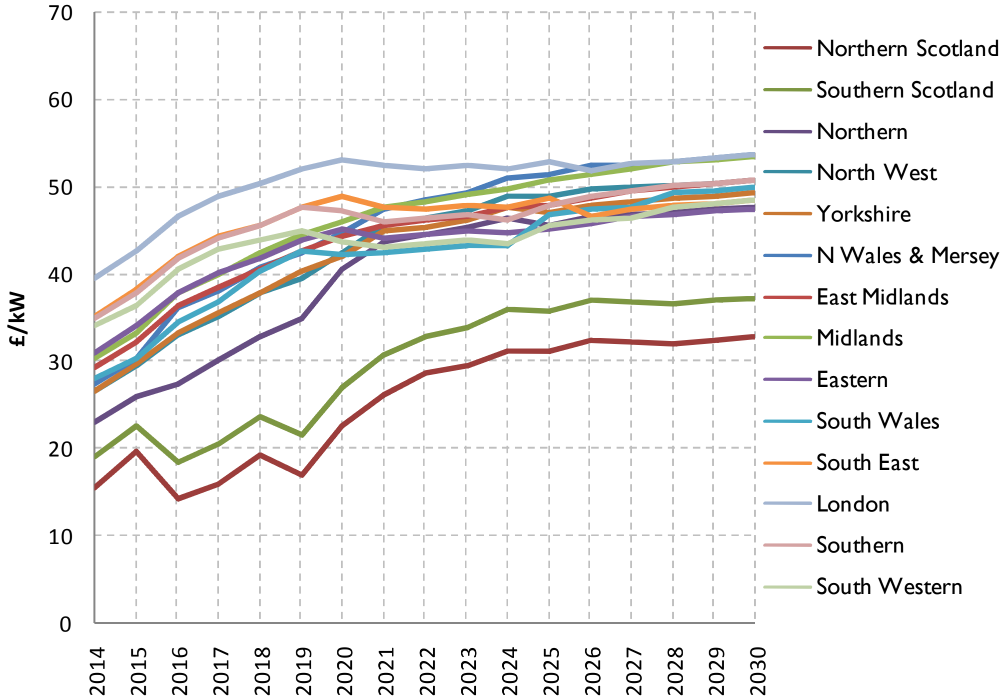

Figure A 1.50 - Illustrative HH Demand tariffs by zone: Diversity 1

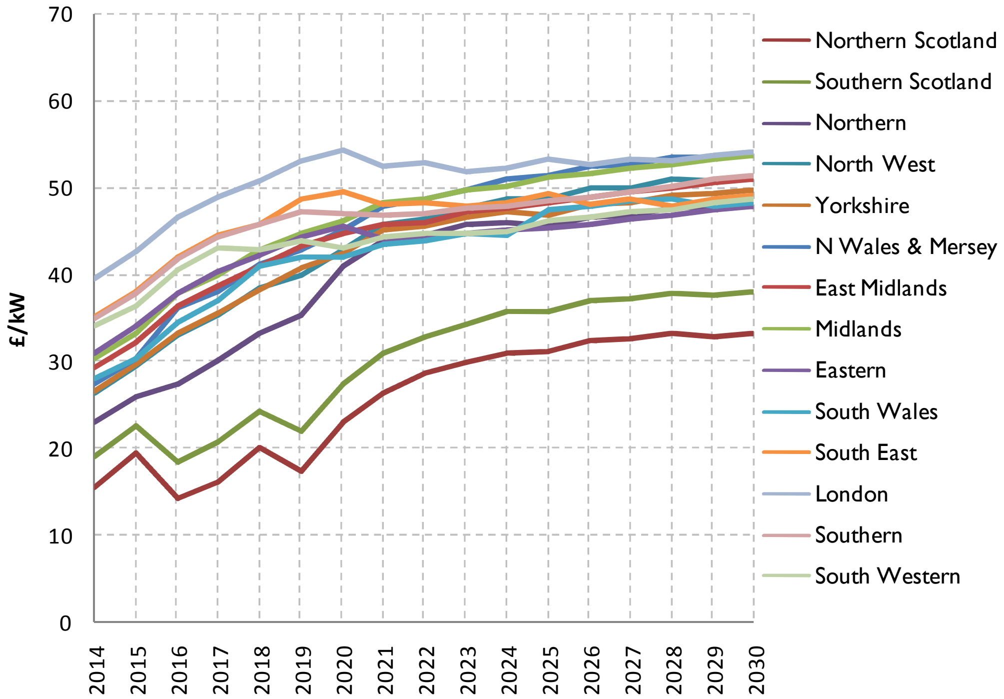

Figure A 1.51 - Illustrative HH Demand tariffs by zone: Diversity 2

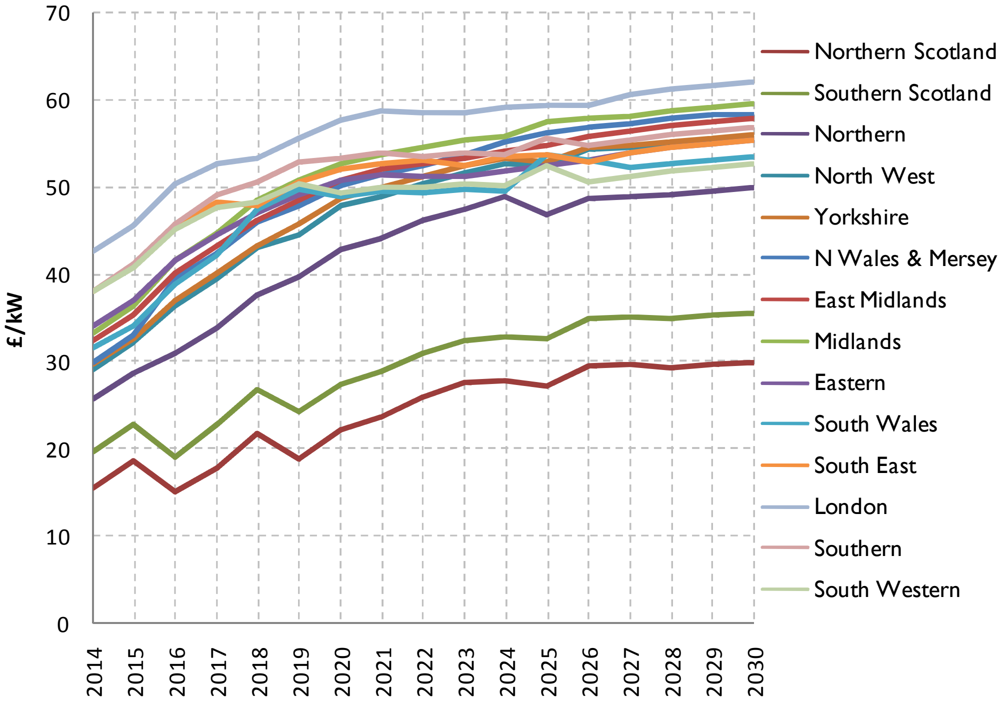

Figure A 1.52 - Illustrative HH Demand tariffs by zone: Diversity 3

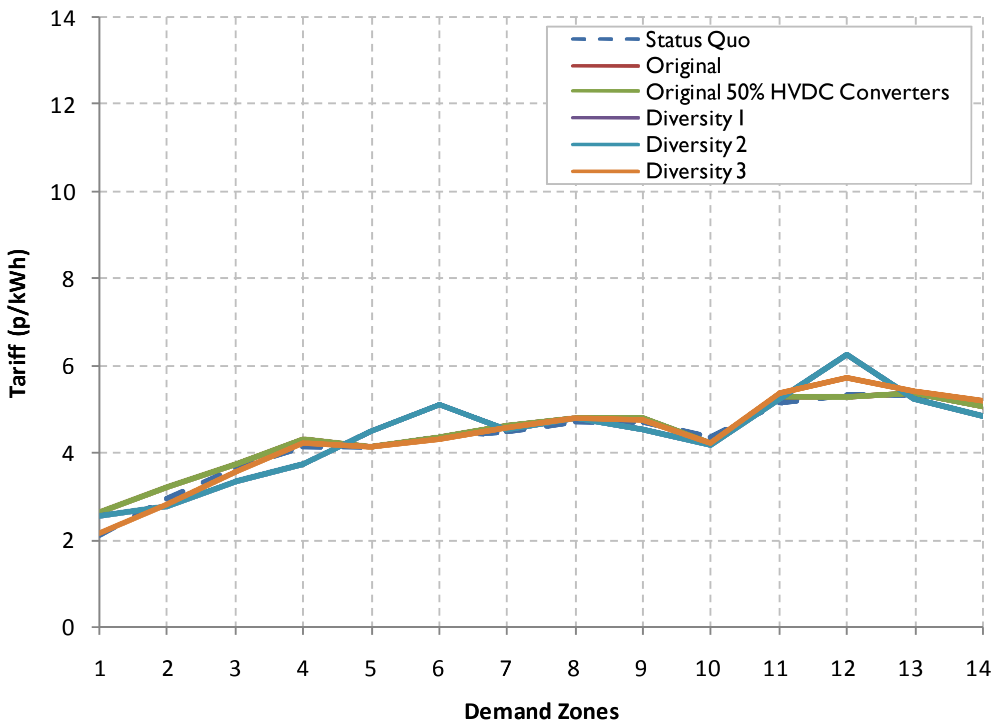

Figure A 1.53 - 2014 illustrative NHH Demand tariffs

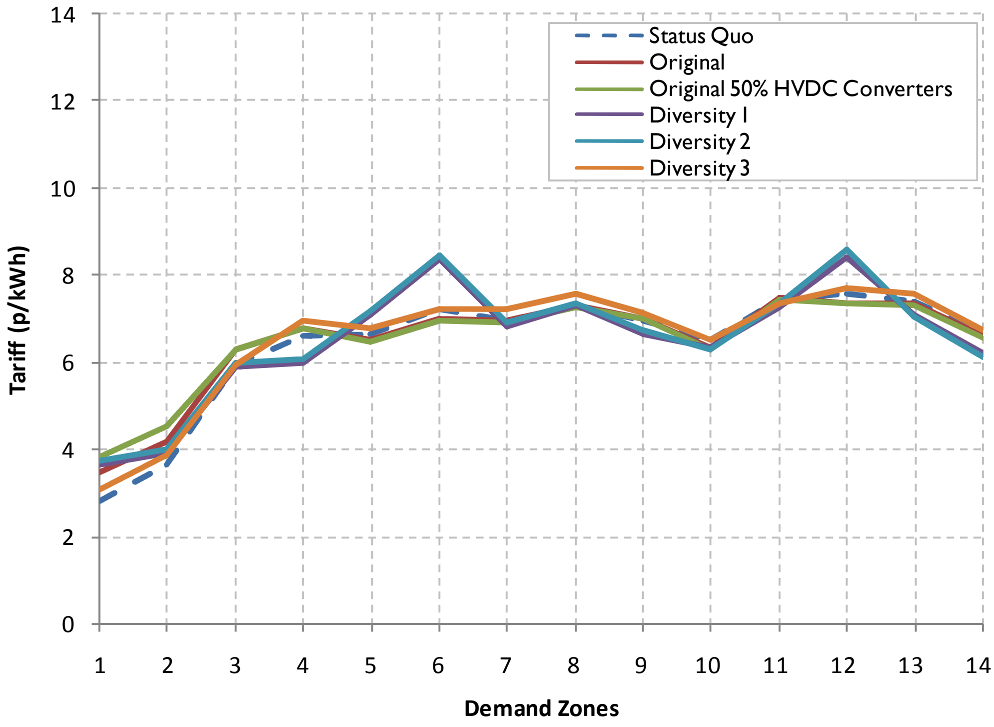

Figure A 1.54 - 2020 illustrative NHH Demand tariffs

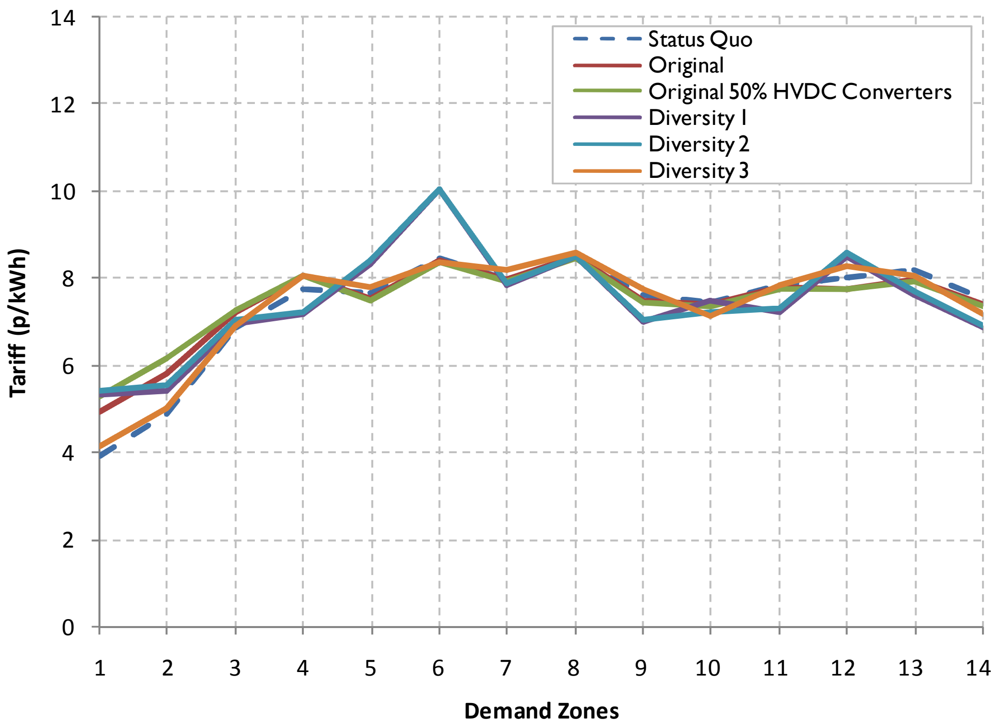

Figure A 1.55 - 2030 illustrative NHH Demand tariffs

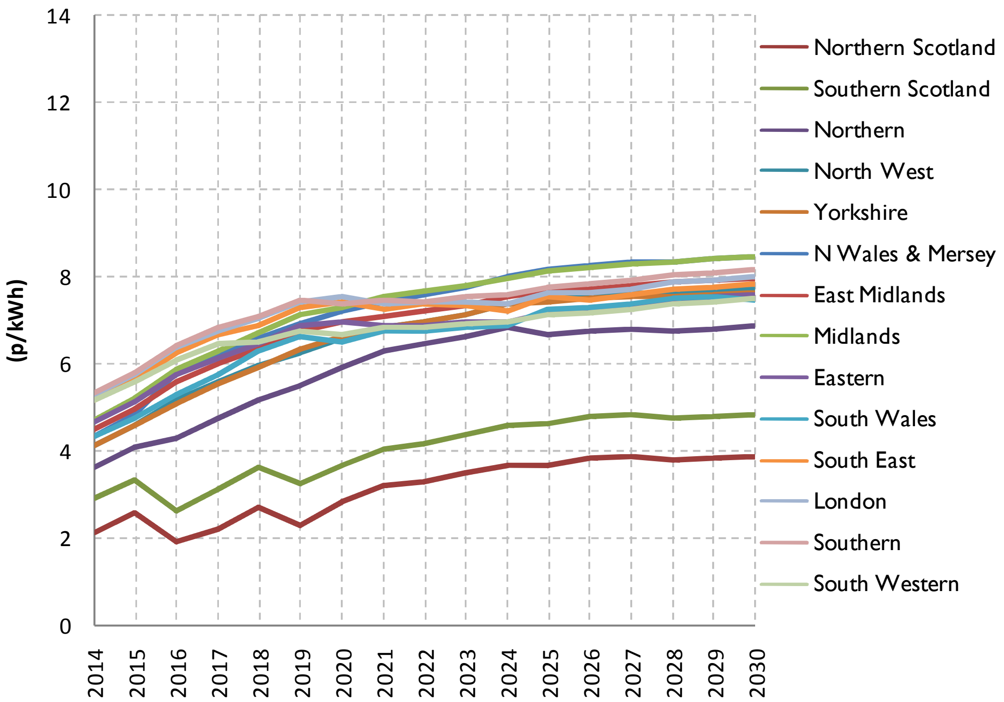

Figure A 1.56 - Illustrative NHH Demand tariffs by zone: Status Quo

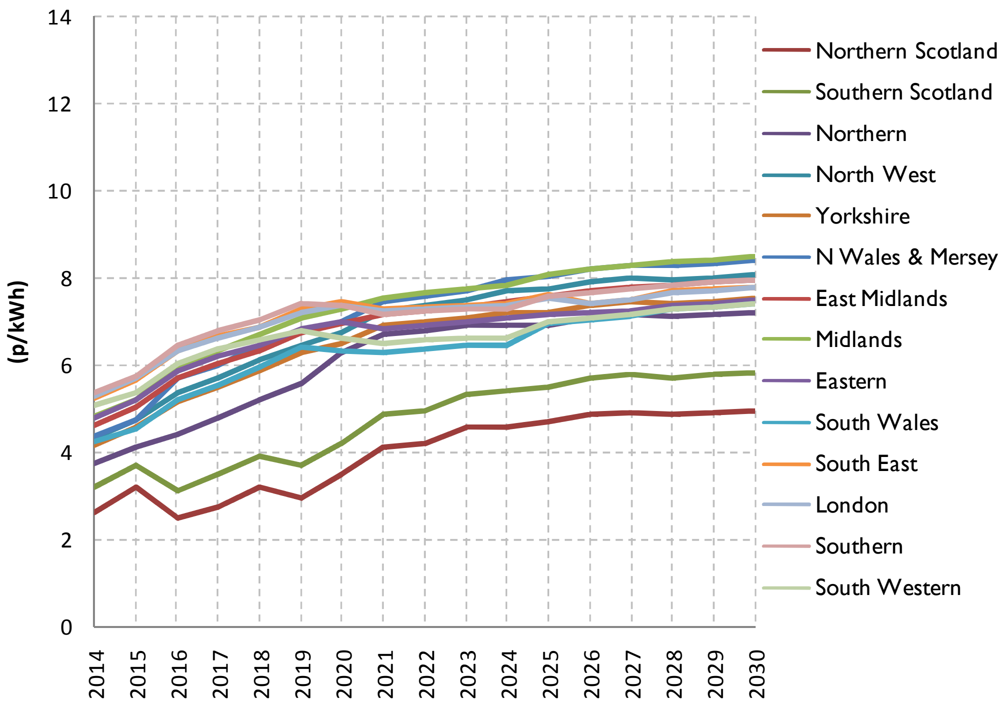

Figure A 1.57 - Illustrative NHH Demand tariffs by zone: Original proposal

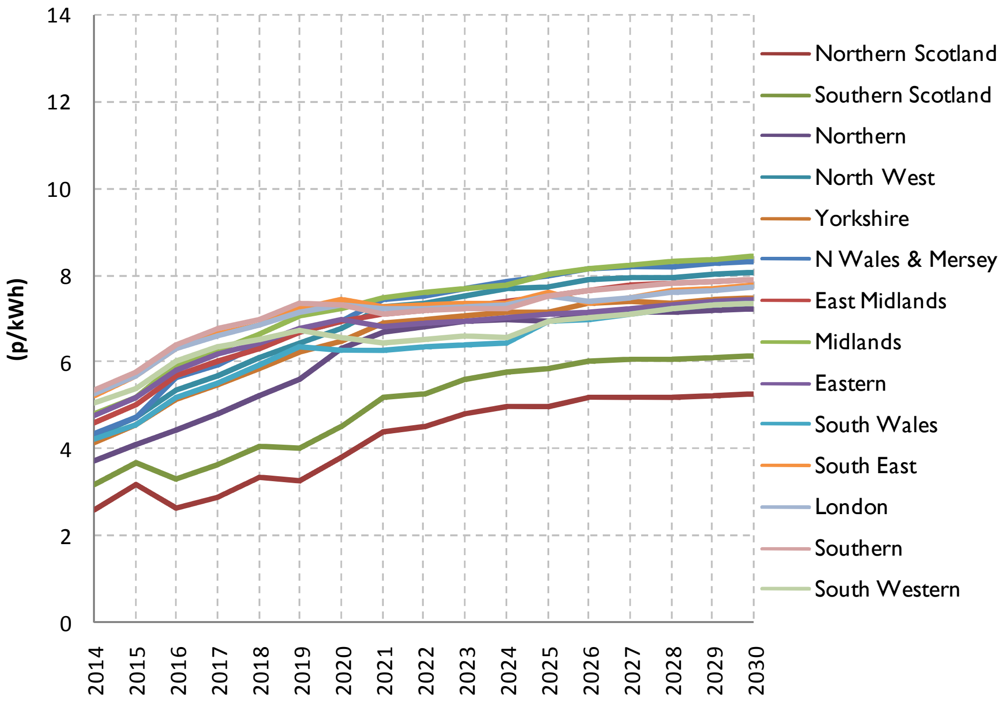

Figure A 1.58 - Illustrative NHH Demand tariffs by zone: Original 50% HVDC Converters

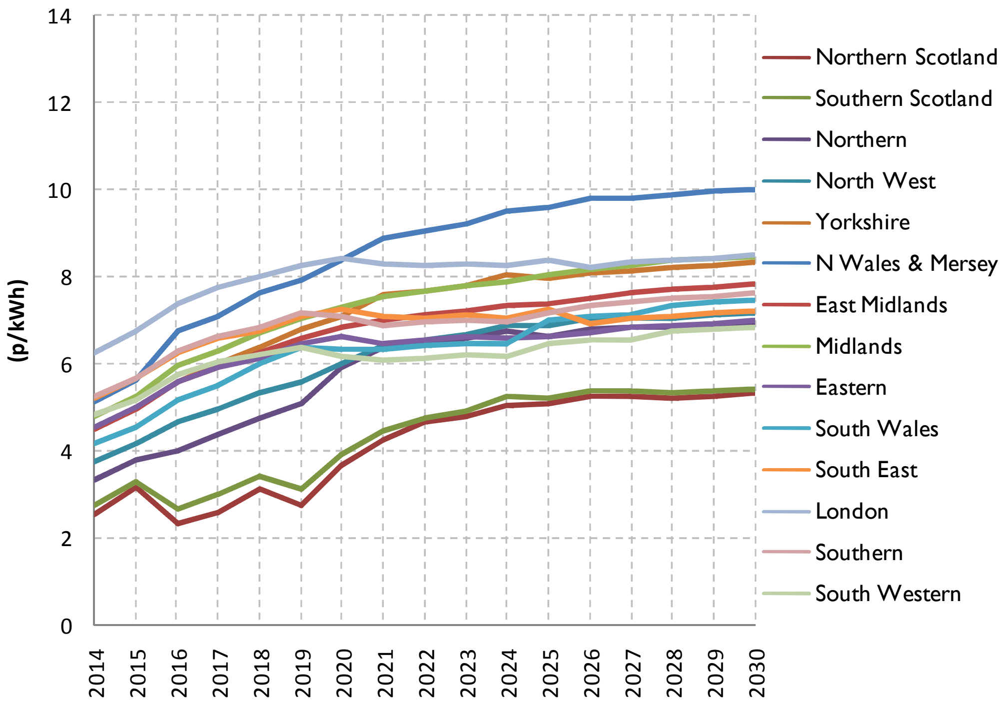

Figure A 1.59 - Illustrative NHH Demand tariffs by zone: Diversity 1

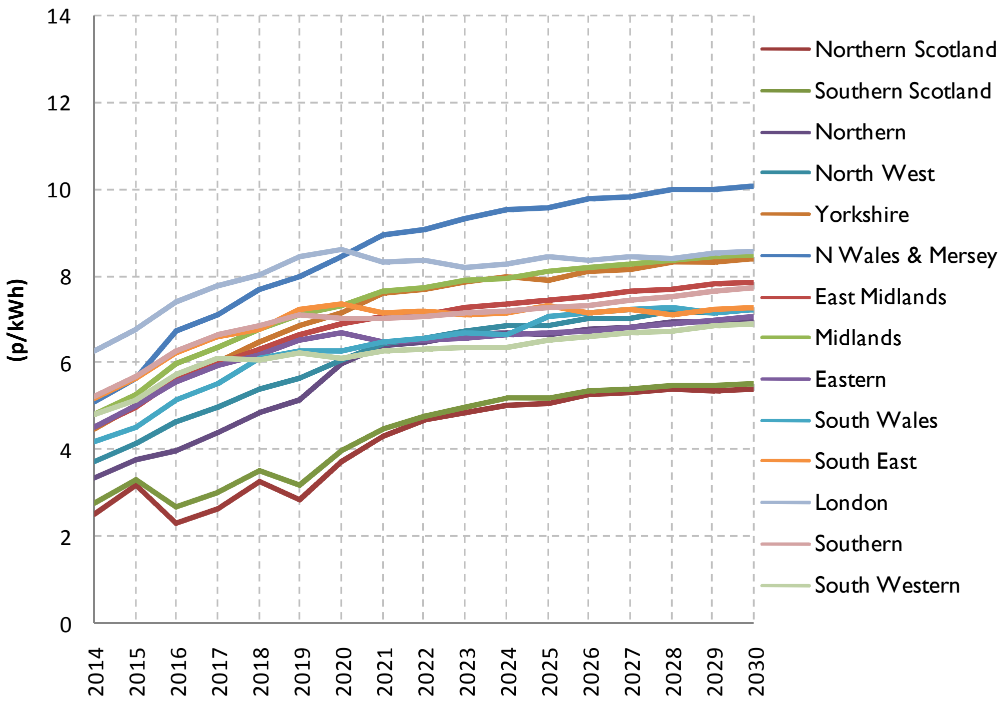

Figure A 1.60 - Illustrative NHH Demand tariffs by zone: Diversity 2

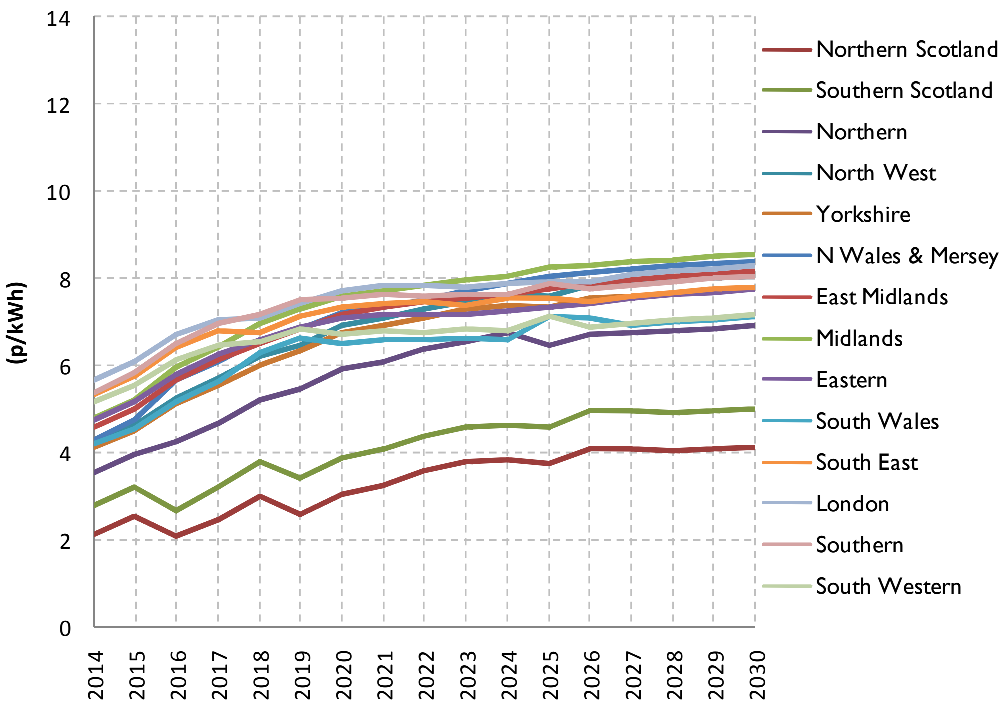

Figure A 1.61 - Illustrative NHH Demand tariffs by zone: Diversity 3

Annex 2 – Review of assumption updates and model developments for CMP213 Impact Assessment Modelling

REDPOINT a business of Baringa

CMP213 modelling

Review of assumption updates and model developments for CMP213 Impact Assessment Modelling

Version:1.0 **Date:**07/05/13

Version History

Version	Date	Description	Prepared by	Approved by
1.0	07/05/2013	Review of changes to Transmit model for CMP213	Nick Screen	

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Contents

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Review of updated assumptions and model developments

1 Introduction

This document reviews the changes made by National Grid to the input modelling assumptions for the CMP 213 Impact Assessment, compared to the modelling conducted by Redpoint Energy for Ofgem's Project TransmiT SCR (hereafter referred to as 'TransmiT results').

The scope of the review is to:

1. Comment on whether the choice of updated assumption is justifiable and consistent with TransmiT
2. Ensure that the updated assumptions have been implemented correctly in the modelling framework

The document also contains a summary of the model developments made to the modelling framework.

2 Assumptions review

2.1 Sustainability

The modelling has been completed with a 'Stage 2' approach to the setting of CfD strike prices across different transmission charging policy variants. Under this approach, each model has been calibrated to meet Government targets[1] to comply with the EU Renewable Energy Directive in 2020 and plans for decarbonisation to 2030 consistent with carbon budgets. The following table provides a summary of these targets, and the allowable deviations assumed.

Metric	2020 target	2030 target	Allowable range
Renewable share (% of demand[2])	30%	-	30% to 32% in 2020
Carbon intensity(g/kWh)	-	~100	95 to 105 in 2030
Nuclear capacity (GW)	-	14	-

[1] Coalition Announces Transformation of Power Market, DECC Press Release, December 2010 (https://www.gov.uk/government/news/coalition-announces-transformation-of-power-market).

[2] Electricity demand is based on EU definition (includes energy industry own use and pumped storage, excludes consumption in rail transport). Carbon intensity excludes emissions from embedded CHP.

In addition to these targets the total level of subsidy payments made to low carbon generation will be set at a level that ensures that the governments Levy Control Framework level target spend[3] for 2020/21, announce as part of the recent Energy Bill will not be exceeded.

2.2 Commodity prices

Commodity price assumptions for Gas and Coal have been updated in line with the Central scenario from DECC's 2012 Energy and Emissions Projections[4], converted to £/MWh prices[5].

Whilst DECC's updated price projections include an updated view of crude oil prices, and this is the main driver behind oil product prices, no updated view of these have been published. Therefore for Fuel Oil and Gas Oil prices, historic data[6] published by DECC has been utilised, to undertake a simple linear regression against DECC's crude oil price projections to obtain updated price forecasts. This methodology is similar to that undertaken by National Grid to develop its analysis of future energy scenarios.

All other commodity prices have been inflated by RPI to 2012/13 prices.

A single commodity price scenario has been constructed. No commodity price sensitivities have been modelled.

[3] An Energy Bill to power low-carbon economic growth, protect consumers and keep the lights on, DECC Press Release, November 2012 (https://www.gov.uk/government/news/an-energy-bill-to-power-low-carbon-economic-growth-protect-consumers-and-keep-the-lights-on).

[4]Annex F, https://www.gov.uk/government/publications/2012-energy-and-emissions-projections,

[5] A calorific value of 25.1GJ/t for coal has been assumed (based on quoted values for ARA (Antwerp-Rotterdam-Amsterdam) coal).

[6] Table 3.2.1 Average prices of fuels purchased by the major UK power producers and of gas at UK delivery points (Fuel Oil Prices) & Table 3.1.4 Annual prices of fuels purchased by manufacturing industry (p/kWh) (Gas Oil Prices) of DECC's Quarterly Energy Price Publication, December 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65940/7341-quarterly-energy-prices-december-2012.pdf)

2.3 Carbon prices

Assumptions for the cost of carbon that generators will face are in line with DECC's forecasts published in the Updated short-term traded carbon values for modelling purposes[7] document inclusive of the Carbon Price floor.

2.4 Electricity demand

Demand assumptions are based upon National Grid 2012 Gone Green scenario, as published in the National Grid 2012 Ten Year Statement[8]. This provides peak demand assumptions and references National Grid's Future Energy Scenarios[9] for annual demand assumptions. The ratio of peak to annual demand changes across the modelling horizon. A limitation of the current models is that the ELSI inputs do not currently allow for a change in the shape of demand over time, therefore the ratio of peak to annual demand has been kept constant over time. The impact of this is that annual demand is 330 TWh in 2030, rather than the 340 TWh in Gone Green.

2.5 Potential generation build

The list of generation projects assumed for 2011-15 has been fixed based upon the contracted generation background as published in the TEC register, based upon the logic that such projects are either already delivered or at a sufficiently advanced stage of their development that their year of commissioning will be as expected.

The impact of this is that the model results for generation investment decisions will be identical to 2015.

For 2016 onwards, the assumed list of available generation projects, and underlying global maximum and minimum build assumptions for each technology type has been largely based upon Redpoint Energy's originally modelled assumptions.

In compiling the final data, the total potential capacity for each technology type has been compared with both the contracted background and that assumed in National Grid's accelerated

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[7] Table 2, Updated short-term traded carbon values used for modelling purposes, DECC, October 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/41797/6664-carbon-values-used-in-deccs-emission-projections-.pdf)

[8] Gone Green Peak Outturn and Forecast, Figure 2.3.1, National Grid's 2012 Ten Year Statement (http://www.nationalgrid.com/uk/Electricity/ten-year-statement/current-elec-tys/).

[9] Figure 24, *http://www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/56766/UKFutureEnergyScenarios2014.pdf*)

growth scenario[10]. In cases where the total capacity for a technology type under the accelerated growth scenario outweighs the assumptions previously made by Redpoint Energy, or where additional projects are contracted that do not align with the generic generation categories used under Redpoint Energy's previous assumptions, the background has been amended to include the additional generation. Most notable changes include:

i) updates to available offshore wind capacity to match contracted TEC and dates, which are reflective of the accelerated growth scenario.
ii) the addition of Biomass capacity to match the accelerated growth scenario;
iii) the addition of Hydro capacity to match the accelerated growth scenario;
iv) the addition of potential Scottish Island based tidal plant;
v) the addition of potential Alderney based tidal plant; and
vi) the addition of a potential 490MW CHP station connecting at Pembroke.

Updates have also been made in relation to existing generation to reflect revised TECs. This includes changes (mainly reductions) to coal and CCGT TECs, and adjustments to a small number of wind TECs

The location of the wind farms has also been revised to adjust a number of cases where the original ELSI plant list did not have these mapped to the correct zones (mainly due to being on the border of two zones).

2.6 Generation life expectancy

With the exception of nuclear stations, no amendments have been made to expected station closure dates previously assumed by Redpoint Energy. After discussion with the Working Group, the following assumptions on the life expectancy of the existing nuclear fleet: were assumed:

[10]Accelerated Growth Fuel Type Mix, Table F2.3, National Grid's 2012 Ten Year Statement (http://www.nationalgrid.com/uk/Electricity/ten-year-statement/current-elec-tys/).

Plant	Capacity (MW)	Closure date
Dungeness B	1081	2018
Hinkley Point B	1261	2023
Oldbury	215	2012
Hunterston	1074	2023
Torness	1215	2030
Hartlepool	1207	2019
Heysham 1	1203	2019
Heysham 2	1203	2030
Sizewell B	1212	2035
Wylfa	890	2014

These assumptions include seven year life extensions for Torness and Heysham 2. Note that these are subject to approval, a more conservative view has been taken by the Working Group than that of EdF Energy, who expects on average seven year life extensions across its AGR fleet[11] (including extensions previously announced for Hinkley Point B and Hunterston B).

2.7 Generation Capital and Operational Cost Information

Capital and non-use of system operating cost information has been updated for conventional[12] and non-marine based renewables[13] based upon recent studies commissioned by DECC.

[11] EDF Energy announces seven year life extension to Hinkley Point B and Hunterson B nuclear power stations, Press Release, December 2012 (http://www.edfenergy.com/media-centre/press-news/EDF-Energy-announces-seven-year-life-extension-to-Hinkley-Point-B-and-Hunterston-B-nuclear-power-stations.shtml).

[12] For conventional plant the majority of data was taken from: Electricity Generation Cost Model – 2012 Update of Non Renewable Technologies, Parsons Brinckerhoff (on behalf of DECC), August 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65712/6884-electricity-gen-cost-model-2012-update.pdf). However, revised CO_2 transportation costs for CCS plant were updated in DECC's subsequent Electricity Generation Costs report, October 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65713/6883-electricity-generation-costs.pdf).

[13] Government response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012, DECC, July 2012 (https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42852/5936-renewables-obligation-consultation-the-government.pdf).

Identical learning rates to those used in Redpoint Energy's previous analysis have been applied to nth of a kind capital costs for nuclear and CCS technologies to model the reduction in the cost of emerging technology as time progresses. For operational costs, nth of a kind costs were assumed for both technology types.

All other cost data has been inflated by RPI to 2012/13 prices.

2.8 Transmission reinforcements

The list of potential transmission reinforcements and associated cost information previously used in Redpoint Energy's previous analysis were updated, based upon the final RIIO proposals for each TO[14][15].

Where specific cost information was not available, press releases and information direct from each TO were examined. If such information was not made publically available, then Redpoint's cost assumptions were inflated by RPI to 2012/13 prices.

Furthermore, where specific capability information was not available in the final RIIO proposals for each reinforcement the National Grid Ten Year Statement was used to provide this.

In addition to known reinforcements, an identical set of generic reinforcements for each boundary to those used in Redpoint Energy's previous analysis were assumed, at a cost inflated by RPI to 2012/13 prices.

All projects to be delivered by 2015 have been set as pre-committed as these projects are assumed to have been initiated due to timescales involved.

The following table provides the base assumptions used:

Reinforcement package	Cost (£m, 2012/13 real)	Boundaries Reinforced	Earliest Date	Notes
Beauly-Denny overhead line	618	B1, B2, B4,	2015	Pre-committed
East Coast (Kincardine - Harburn) 400kV	129	B5,	2018	
Western HVDC Link	1082	B6, B7a,	2016	Pre-committed

[14] Final RIIO-T1 proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd (http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=190&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes)

[15] Final RIIO-T1 proposals for NGET (http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/1_RIIOT1_FP_overview_dec12.pdf)

Reinforcement package	Cost (£m, 2012/13 real)	Boundaries Reinforced	Earliest Date	Notes
Anglo-Scottish Series & Shunt Compensation	391	B6, B11,	2015	Pre-committed
Eastern HVDC Link	1442	B2, B4, B6, B7a,	2018	
Penwortham QBs	31	B7a,	2014	Pre-committed
New Hinckley Point - Seabank OHL and assoc works	647	B10, B13,	2018	
Reconductoring circuits in East Anglia	95	EC5,	2019	
New OHL &reconductoring work in East Anglia	270	EC5,	2019	
QBs in East Anglia	42	EC5,	2021	
Establish 2nd Pentir-Traw 400kv circuit	191	NW2,	2018	
Series compensation and reconductoring work in North Wales	106	NW2,	2016	
Wylfa-Pembroke 2GW HVDC link	834	B8, B9, B12, B17, B202, NW2,	2018	
Daines 225MVAR MSC DNs	5	B8, B9,	2014	Pre-committed
Sundon and Ratcliffe 225MVAR MSCs	11	B8, B9,	2015	Pre-committed
North London Reinforcements & St John's Wood - Hackney cable	488	B14, B15,	2016	Pre-committed
Turn in Sundon - Cowley circuit at East Claydon	53	B8, B9, B12, B14,	2017	
North East London uprate to 400kV	90	B14, B15,	2019	

Reinforcement package	Cost (£m, 2012/13 real)	Boundaries Reinforced	Earliest Date	Notes
East London reinforcements	32	B15,	2014	Pre-committed
East London reconductoring	74	B15,	2016	
Kingsnorth-Cobham reconductoring	21	B15, EC5,	2016	
South London reconductoring	80	B15,	2016	
Essex reconductoring	37	B15,	2016	
QBs in Sundon-Wymondley circuits	32	B14,	2015	Pre-committed
London MSCs, East End reconductoring	48	B14,	2015	Pre-committed
New reactor at Rayleigh	37	B15,	2016	
Rowdown, Canterbury, Sellinge and Dungeness reinforcements	122	B15,	2019	
Iver, East Claydon, Grendon&Elstree new MSCs	32	B8, B9,	2015	Pre-committed
Cottam - West Burton reconductoring	5	B8,	2014	Pre-committed
West Weybridge 275kV additional MSC	5	B9, B14,	2017	
Beauly-Blackhillock-Kintore	91	B1,	2014	Pre-committed
Hunterston-Kintyre link	213	B3,	2015	Pre-committed
East Coast Upgrade	402	B2, B4, B5,	2017	
Humber - Walpole HVDC	613	B8, B9, B11,	2020	
Caithness - Moray HVDC	1061	B1,	2018	
Eastern HVDC Link #2	769	B6, B7a,	2019	
Western HVDC Link #2	1082	B6, B7a,	2020	Same cost as

Reinforcement package	Cost (£m, 2012/13 real)	Boundaries Reinforced	Earliest Date	Notes
				Western HVDC Link #1 assumed
West Midlands MSC	50	B17	2022	Pre-committed
B1	75	B1,	2021	
B2	75	B2,	2021	
B3	113	B3,	2021	
B4	100	B4,	2021	
B5	100	B5,	2021	
B6	150	B6,	2021	
B7a	171	B7a,	2021	
B8	121	B8,	2021	
B9	241	B9,	2021	
B10	15	B10,	2021	
B11	206	B11,	2021	
B12	25	B12,	2021	
B13	342	B13,	2021	
B14	52	B14,	2021	
B15	8	B15,	2021	
B16	30	B16,	2021	
B17	103	B17,	2021	
B201	52	B201,	2021	
B202	8	B202,	2021	
EC5	25	EC5,	2021	
NW2	50	NW2,	2021	

The costs for HVDC bootstraps, which are relevant both for transmission reinforcement and for transport model expansion factor calculations, have been sourced from 2011 Offshore Development Information Statement[16], inflated to 2012 prices, and updated following discussion with relevant TOs.

Component	Rating (GW)	Cost (£m)
DC Cable	2 GW	£1.3m/km
DC Cable	1 GW	£1.1m/km
DC Cable	0.5 GW	£0.9m/km
Onshore Convertor Station	2 GW	£130m
Onshore Convertor Station	1 GW	£115m

2.9 Island subsea links

The specific link costs relating to Original and 50% HVDC options which are then used to provide local circuit charges use information provided by SHE-T and are replicated in Volume 2, Annex 17 of the CMP213 Code Administrator Consultation.

2.10 Allowed Transmission Revenues

Base TO revenues relating to non-load related investment have been calculated in line with the final RIIO proposals[17][18], and have been projected forwards beyond the end of the forthcoming price control period out to 2030/31. An additional load related revenue element has been added based upon the level of transmission investment that results from the transmission decision element of the model.

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17 Final RIIO-T1 proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd (http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=190&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes)

18 Final RIIO-T1 proposals for NGET (http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/1_RIIOT1_FP_overview_dec12.pdf)

Whilst the underlying methodology is identical to that undertaken in Redpoint Energy's Project TransmiT analysis, the relating financing and rate of return assumptions have been updated in line with the final proposals for NGET.

2.11 Transport & Tariff Model Assumptions

Whilst the model has not been updated to use the latest 2013/14 generation TNUoS zones, other Transport & Tariff Model data, including the expansion constant and expansion factors have been updated to represent the values used in the calculation of final TNUoS tariffs for 2013/14[19]. To maintain a 2012/13 price base for the modelling, the expansion constant was converted to 2012/13 prices, by deflating the 2013/14 by RPI. The transmission network within the Transport and Tariff models is based on 2012/13 data updated with changes for 2013/14 and 2014/15, with account taken of HVDC bootstraps.

2.12 G:D split

Unlike the previous analysis undertaken by Redpoint Energy, a generation:demand revenue recovery split of 27:73 has been assumed throughout the modelling.

The Transmit modelling assumed a change in the G:D split to 15:85 in 2015. This was an assumption based on advice from National Grid on the change required in order to be consistent with potential future EU tariffication guidelines and its review was within scope of the TransmiT SCR. The conclusions of the TransmiT SCR were that it was not necessary to change the G:D split, although National Grid should keep under review.

[19]Section 3.3.1, http://www.nationalgrid.com/NR/rdonlyres/E1CC114B-4815-447D-BDE9-39D2FC31D08B/58728/FinalTNUoSTariffsin13_14.pdf

3 Model developments

A range of enhancements were made to the modelling suite. The table below summarises the changes made to the model functionality.

Change	Description
Capacity mechanism modelling	The Capacity Mechanism functionality has been revised to more closely match the options presented in the Energy Bill 2012. A start date has been added for the Capacity Mechanism. The modelling assumes that the first payments are made in 2018. New plant that are not under CfDs receive a multi-year contract (for the remainder of the modelling horizon i.e. up to 12 years). The capacity of these new planted is netted off the total requirement in the following years.
Impedance calculation for parallel HVDC bootstraps	National Grid has fully incorporated within the Transport and Tariff models for all modelled options the methodology proposed by the CMP213 Workgroup for parallel HVDC impedance calculation. Previously, under the SCR Impact Assessment, this calculation was undertaken outside the Transport and Tariff model.
Update CBA calculation to use ‘ex-post’ transmission costs	In the Transmit modelling, the CBA results were originally presented using a forecast of the transmission costs rather than the final values. The final TransmiT results were re-presented using the ‘ex-post’ transmission costs. The model has been updated so that these are used automatically.
Update CBA calculation to use vintaged capital costs	The CBA calculation for annual capital costs assumed the prevailing capital costs, rather than basing these depending on the costs when different plant were built. Changed to used vintaged costs
Adjust offshore wind depth to cost relationship	Calculation of the impact of depth/distance on offshore wind capital costs has been re-calibrated

3.1 Usability changes

In addition to the changes above, a set of changes were made to make the modelling suite easier to use, by streamlining and rationalising certain elements. These changes included:

- Rationalisation of model links
- Removing unused buttons and functionality
- Reviewing and updating model progress messages
- Adding additional error handling
- Rationalisation of key input data tables
- Rationalisation of data transfer between model components
- Further automation of outputs generation

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Mr Gavin Barr, Executive Director, Development & Infrastructure* *Tel: 01856 873535 ext. 2301* *Email: gavin.barr@orkney.gov.uk*
Company Name:	*Orkney Islands Council*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. *The development of wind, wave, and tidal stream resources in and around Orkney – some of the richest renewable resources in the UK – is a key part of the Council's strategic plan for the*

	islands. Orkney can make an important contribution to UK and Scottish Government targets for renewable energy, but only if the infrastructure is available, at a fair price, to enable energy to be exported to markets in the south. *The work of Project TransmiT in relation to transmission charging methodology is therefore of great interest to the Council. The Council is aware of the CUSC objectives which modifications to the CUSC must meet. It believes that the deliberations of the Working Group and the current consultation have shown ways in which the methodology can be changed to better meet the objectives and help in lowering the transmission charge barrier to renewables development.* *The proposed charging regime for intermittent generators, based on network sharing, is a welcome change. The Council has supported the work of Heriot Watt's Institute of Islands Technology, which showed that network sharing by diverse renewables technologies could be very significant, on the basis of projected mixes of technologies in Orkney. The Council is pleased that the Counter Correlation factor (CCF) has been incorporated in the Original and Alternatives, although it believes that this should be applied in an anticipatory manner where cable-sharing is planned. Cable-sharing represents the efficient use of cable capacity where there is a mix of renewables technologies, and is well-suited to the diverse resources available in Orkney and other peripheral areas. It should be encouraged as much as possible.* *The use of Annual Load Factor on the mainland as a proxy for sharing avoids the unpredictable variability of charges which use of a diversity factor could introduce. Investors require certainty about project costs and transmission charges are an important part of project cost structure.* *In respect of charging for the use of HVDC cables, the Council supports Alternatives which exclude part of the converter station costs, on the basis of analogy with the treatment of AC cables, and on the grounds of additional resilience to the whole system. This treatment of converter station costs should apply equally to island spurs and to parallel cables. To do otherwise would undermine competition between generators in the islands and on the mainland.* *Retention of the security factor for single circuits to islands at 1.0 instead of 1.8 is logical in terms of the cost-reflective objective. The redefinition of MITS for islands, to require two interconnectors, is acceptable provided this is purely for the purpose of the proposed methodology for determining charges, since there could be other implications, not currently foreseen, which might unexpectedly disadvantage the islands.*

	In the Council's view the Original and some of the alternatives, which reflect the points made above, better meet the CUSC objectives. Overall, the Council favours WACM 7, which combines the use of ALF and the Counter Correlation Factor as in the Original, with 70% exclusion of HVDC converter costs in the islands and 60% for bootstraps.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	*Since the planned completion date of the first transmission cable to Orkney has now been delayed to 2018 the date of implementation, as between 2014 and 2015, is not of great moment to Orkney. However, greater investor certainty about charges is long overdue, in order to allow firm project plans to be made, and therefore the sooner that transmission charges based on a new methodology can be announced, the better.*
Do you have any other comments?	*The delay in the completion date of the first planned Orkney transmission link from 2016 to 2018 is a matter of considerable concern to the Council, since it delays projects which could be undertaken, to the benefit of the local economy, and of the Government's renewables targets. Changes in the regulatory framework which create investor uncertainty are one of the causes of delay. Difficulties of securing access to transmission capacity is another cause. A period of regulatory certainty and stability would do much to encourage developers and investors to commit to the renewables projects which the UK urgently requires.*

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Rosalind Hart* *R.Hart@Pelamiswave.com*
Company Name:	*Pelamis Wave Power*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We thank the National grid for the opportunity to feed into the CMP213 consultation process and acknowledge the work which has gone into the proposals presented for consideration. We believe that WACM number 7 is the best overall option. Our reasons for this decision are set out below; **Sharing:** **No diversity** This is our preferred option. We believe there is a strong evidence base for an ALF link to incremental constraint costs, and a more consistent and long lasting relationship than other shorter term effects of bid price and diversity of plant in an area. We support no diversity overall as this improves cost reflectivity without excessive complexity and links variability in charges with variability in useage, which is manageable by generators. **Diversity method 1** Impact of diversity on incremental costs has been demonstrated in principle, but we are concerned that all the Diversity methods whilst attempting to improve the resolution of cost signals (i.e. average ALF to more specific targeting on zones) require some subjective assumptions for what is a complex and changing picture, so improvement in accuracy is debateable. Furthermore, the variability of charges being linked to diversity cannot be managed by generators as they have no control over where other generators locate. Of the three Diversity methods,

	Diversity method 1 employs LC/C assumptions but does not cap sharing at 50% (see Diversity 2&3 for comment on this), and it also avoids any on/off sharing signals for boundaries. On that basis, Diversity 1 is considered to be an improvement on the baseline but not an improvement on options with no diversity. **Diversity method 2 & 3** Diversity Methods 2 and 3 rather arbitrarily limit sharing at 50%, for which there is no empirical evidence. Therefore we feel it is a step too far and requires more evidence. **Form of sharing:** **ALF 5 year historic** We prefer this form of sharing as it is transparent, employs user data and is practical. **Parallel HVDC & Islands:** **Specific expansion factor (EF) targeting 100% of Converter costs** Targeting 100% of the costs locationally is inequitable with cost allocation in existing mainland expansion factors, and inconsistent with TNUoS principles which do not target fixed costs. **Specific EF, Generic 40% targeting of Converter costs for AC substation equivalence and Quad Booster-like benefits** This is our preference. Removing these costs achieves better parity with existing expansion factors and is more consistent with TNUoS methodology. **Specific EF, generic 50% targeting of converter costs for AC substation equivalence** Whilst this option does recognise equivalence on treatment of AC substations it does not attempt to target other fixed costs in the AC system. **Specific EF, target according to removal of the exact cost of AC equivalent costs in each converter station** As above, although recognise enhanced cost reflectivity of specific treatment, suspect cost breakdown will not be practicable to obtain.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We favour an implementation date of the 1 April 2014. We would not wish implementation to be delayed for one or two parties and would hope the impact could be managed on a case-by-case basis.
Do you have any other comments?	We acknowledge the work undertaken by the National Grid and the Workgroup during the CMP213 process. We would take this opportunity to re-stress the importance of an effective island charging solution to the emerging wave & tidal sector and of the widely reported benefits that opening up generation in the Islands can bring. Lastly, whilst we feel that the results presented in the consultation are sufficient to understand the broad direction of travel of impacts, we do feel that the results would be enhanced by some commentary for those parties interested in interpreting the results in the context of the modelling methodology. We welcome National Grid's commitment to do this through their response to the Code Administrator consultation, and would welcome the opportunity for any clarifications arising via TCMF or some other informal forum, before Ofgem's own impact assessment.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

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Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

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Respondent:	Tim Russell tim@russellpower.co.uk 01793 751369
Company Name:	Renewable Energy Association
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

	We believe that the original proposal and all of the alternatives better facilitate the Applicable CUSC Objectives. Because the proposed methodology is more cost reflective of the costs that generators of different types impose on the transmission system than the status quo objective (b) is axiomatically better facilitated and by being more cost reflective objective a facilitating competition is also better facilitated. By reducing charges compared to the status quo in northern wind rich areas it also allows otherwise marginal generation of this type to proceed which should also increase competition in generation. Applicable CUSC Objective C is better facilitated as under the current methodology there is no means of incorporating direct current circuits that run in parallel with the alternating current system into the charging methodology.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We support an implementation date of 1st April (either 2014 or 2015). Whilst the codified approach works we would also support an implementation on a 1st April less than one year and twenty working days after the Ofgem decision providing provision were made for generators to reduce their TEC if they wished to with less notice than normal i.e. before the new charges were implemented.
Do you have any other comments?	Whilst we think that all of the alternative and the original are better than the status quo our first choice would be: Diversity method 1 Year round historic specific load factors HVDC bootstraps and islands, specific expansion factor with 100% cable and 50% convertor costs included. This corresponds to option 30. The reasoning for choosing these options is as follows: There is always a balance between simplicity and cost reflectivity. Clearly sharing opportunities decrease where there is a predominance of generation of one type and diversity method 1 recognises this in the simplest possible fashion (we exclude diversity 3 which does not recognise the dual planning background). In terms of dc links there is some merit in taking out the

	equivalent substation costs that would not be charged in a locational manner for ac substations. About 50% is the right ball park figure or a little bit high but there should be some recognition of the quad. booster function for bootstraps and the reactive compensation and black start features of certain island dc links so this brings the 50% figure from being a bit high to about right.

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Respondent:	*Zoltan Zavody, zoltan.zavody@renewableuk.com*
Company Name:	*RenewableUK*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We believe that both the Original and the Alternatives better facilitate the Applicable CUSC Objectives. On sharing, renewable and in particular wind generators do in general share assets. Recognising this sharing therefore opens up the generation market to more (renewable) generation; and reflects more accurately the costs of transmission. Care needs to be taken that simplicity and effectiveness is not compromised by over-complexity. On HVDC, consideration of the system benefits of HVDC technology is consistent with cost-reflectivity; and again opens up competition amongst generators that might more easily connect through HVDC. On island charging, the facilitation of generation on the islands allows more entrants into the generation market, particularly in these remote areas. Cost-reflectivity needs to be balanced by the need for a stable and predictable charging regime.

Do you support the proposed implementation approach? If not, please state why and provide an alternative	The original rationale for Project TransmiT was “to ensure that arrangements are in place that facilitate the timely move to a low

suggestion where possible.	carbon energy sector." Since 2020 is the legally binding target for renewable deployment, the timeliness of an outcome to the CMP 213 process should be assessed in the context of helping to achieve this target. Adaptation by the industry is facilitated by transparency of impacts, which in turn is greatly helped by simplicity of methodology. In addition, a more detailed commentary on the modelling of impacts would be helpful to foster greater understanding by the wider industry.
Do you have any other comments?	In addition to effective island charging, there is a need for a support scheme that facilitates the deployment of low-carbon energy in the islands. There is a need for the work and outcomes of CMP 213 to tie in with the development of such a support scheme. RenewableUK is pleased to have been a part of the CMP 213 process. We trust that the hard work of all parties concerned will result in material and timely improvements to the energy sector and consequent benefits to its customers.

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Respondent:	*IGNACIO PRIVITERA*
Company Name:	*REPSOL NUEVAS ENERGIAS UK LIMITED*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We believe WACM number 7 is the best overall option. Justifications against the main constituent parts of the Original and the WACM's are as follows: **Sharing – no diversity** Evidence base for ALF link to incremental constraint costs is strong, and a more consistent and long lasting relationship than other shorter term effects of bid price and diversity of plant in an area. Support no diversity overall as improves cost reflectivity without excessive complexity and links variability in charges with variability in useage, which is manageable by generators. **Sharing – diversity method 1** Impact of diversity on incremental costs has been demonstrated in principle, but concerned that all Diversity methods whilst attempting to improve the resolution of cost signals (i.e. average ALF to more specific targeting on zones) require some subjective assumptions for what is a complex and changing picture, so improvement in accuracy is debateable. Furthermore, the variability of charges being linked to diversity cannot be managed by generators as they have no control over where other generators locate. Of the three methods, Diversity method 1 employs LC/C assumptions but does not cap sharing at 50% (see Diversity 2 for comment on this), and it also avoids any on/off sharing signals for boundaries. On that basis, Diversity 1 is considered to be an improvement on the baseline but not an

	improvement on options with no diversity. **Sharing – diversity method 2** Methods 2 and 3 Diversity rather arbitrarily limit sharing at 50%, for which there is no empirical evidence. Therefore feel it is a step too far and requires more evidence. **Sharing – diversity method 3** As Diversity 2 **Form of sharing – ALF 5 year historic** Transparent, employs user data and practical **Form of sharing – hybrid** Less practical to implement than historic ALF but recognise why some generators would prefer it **Parallel HVDC and islands – Specific expansion factor (EF) targeting 100% of Converter costs** Targeting 100% of the costs locationally is inequitable with cost allocation in existing mainland expansion factors, and inconsistent with TNUoS principles which do not target fixed costs. **Parallel HVDC and islands – Specific EF, Generic 40% targeting of Converter costs for AC substation equivalence and Quad Booster-like benefits** Removing these costs achieves better parity with existing expansion factors and is more consistent with TNUoS methodology. **Parallel HVDC and islands – Specific EF, generic 50% targeting of converter costs for AC substation equivalence** Whilst this option does recognise equivalence on treatment of AC substations it does not attempt to target other fixed costs in the AC system. **Parallel HVDC and islands – Specific EF, target according to removal of the exact cost of AC equivalent costs in each**

	converter station As above, although recognise enhanced cost reflectivity of specific treatment, suspect cost breakdown will not be practicable to obtain.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	In terms of implementation date, we favour a 1 April 2014 implementation date, which, we note, is already delayed from the original Project TransmiT timetable. We would not wish implementation to be delayed for one or two players and would hope the impact could be managed on a case-by-case basis.
Do you have any other comments?	We acknowledge the work that National Grid has put into producing these results for the Code Administrator consultation. Whilst we feel that the results are sufficient to understand the broad direction of travel of impacts, we do feel that the results would be enhanced by some commentary for those parties interested in interpreting the results in the context of the modelling methodology. We welcome National Grid's commitment to do this via their own response to the Code Administrator consultation, and would welcome the opportunity for any clarifications arising via TCMF or some other informal forum, before Ofgem's own impact assessment.

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Respondent:	**Patrick Smart** UK Grid Connections Manager patrick.smart@res-ltd.com D +44 (0)191 3000 452 M +44 (0)7500 229 648
Company Name:	*Renewable Energy Systems (RES)*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	RES considers that the proposed original and a number of Workgroup Alternative CUSC Modification proposals (WACM) better facilitate the Applicable CUSC objectives relative to the current baseline. **RES considers that, of all of the options presented to the CUSC Panel, WACM 7 best facilitates the Applicable CUSC objectives** for the following reasons; Sharing: RES considers that the application of a generator's Annual Load Factor (ALF) without adjustment for diversity represents the best balance of meeting Objective A and Objective B. Specifically, RES considers that it would establish a cost-reflective proxy for network sharing (better meeting Objective B) whilst also preserving sufficient simplicity and stability such that effective competition in generation is better facilitated (better meeting Objective A). RES considers that the application of adjustment for diversity, and therefore a three part wider tariff under methods 1 and 2, will introduce complexity and volatility to a level that would pose a barrier to entry. Such measures would run against the direction of travel of other areas of use of system charging, for example EHV Generator Distribution Use of System charges where simplification and stability have been of an absolute priority in

	arriving at the final industry-wide methodology. RES would also question the cost-reflectivity of diversity method 3, in which a single generating background is used and the impact of different types of generators on transmission system investment, as considered by the Transmission Owners in accordance with planning standards, is smeared around all types of generation in a zone. This outcome is also not consistent with the Ofgem SCR direction. <u>HVDC:</u> RES considers that the proposal to include 100% of the cost of the converter station in the expansion factor for HVDC, as set out in the Original proposal, would not better meet the Applicable CUSC objectives. In relation to Objective A, such an approach would be likely to be a barrier to competition for generators connected behind an HVDC link and would create discriminatory treatment relative to generators in equivalent geographical circumstances who are not located behind a HVDC circuit. In relation to Objective B, RES considers that the arguments raised in relation to AC equivalence and also in relation to equivalence with treatment of onshore fixed plant items such as quadrature boosters and substations are valid and that, in order to be truly cost reflective, these factors should be taken account of in determining HVDC expansion factors. RES is firmly of the view that, in order to best meet the Applicable CUSC objectives, costs associated with plant equivalent to that found in AC substations and costs associated with provision of Quad Boosters in AC substations should be excluded from converter costs in determining HVDC expansion factors. In order to promote stability and consistency in TNUoS tariffs, that exclusion should be performed on a generic, and not investment-specific, basis. <u>Islands:</u> For the same reasons as those outlined under the HVDC section above, RES is firmly of the view that, in order to realise the optimum balance of meeting Applicable CUSC objectives A and B, costs associated with plant equivalent to that found in AC substations and costs of plant required to provide reactive power compensation services, where Voltage Source Converter (VSC) technology is deployed, should be excluded from the converter costs that contribute to the overall HVDC expansion factor. In order to promote stability, this exclusion should be performed on a generic percentage basis.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	RES supports the proposed implementation approach but, in doing so, would highlight the need for timely implementation of CMP213 in order to minimise the impact of ongoing uncertainty upon the market.
Do you have any other comments?	In light of the breadth and complexity of the issues to be addressed in progressing CMP213, to say nothing of the tight timescales, RES considers that the work of the CMP213 has been thorough and comprehensive. RES would particularly commend the efforts of the National Grid team in pulling together a huge amount of work in a very short period of time.

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Respondent:	*Please insert your name and contact details (phone number or email address) Bill Reed, bill.reed@rwe.com, 01793893835*
Company Name:	*Please insert Company Name* RWE Supply and Trading GmbH, RWE Npower plc, Great Yarmouth Power Ltd, Npower Cogen Trading Ltd, Npower Direct Ltd, Npower Ltd, Npower Northern Ltd, Npower Northern Supply Ltd, Npower Yorkshire Ltd, Npower Yorkshire Supply Ltd, RWE npower renewables, a wholly owned subsidiary of RWE Innogy GmbH
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

	We do not believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives. It is our view that any objective assessment of the evidence presented to the Working Group of the impact of CMP213 would indicate that it would not better meet the CUSC Objectives. In particular; • **CMP213 original and its alternatives cannot better meet Objective A:** We believe that CMP213 original and its alternatives would have a negative effect on competition as a result of higher power prices caused by an increase in overall transmission costs. Power stations in southern Britain, including renewable plant will see substantial increases in charges despite the fact that they are located close to the main GB demand centres. By contrast power stations, particularly low load factor power stations, in northern Britain will see a substantial decrease in charges (with the potential for a significant increase in constraint costs). CMP213 and its alternatives therefore have the potential for distortive effects in the GB generation market as a consequence of the impact on the marginal costs of generation. These conclusions are supported by the work of Redpoint as part of Project Transmit and the assessment of "improved ICRP" by NERA*. * These reports can be found at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=174&refer=Networks/Trans/PT; and http://www.nera.com/nera-files/pub_transmit_1012_full_report.pdf We believe that the impact assessment of the modification proposal presented in the consultation document is of little value since the assumptions appear out of date (for example with respect to generation zones and Electricity Market Reform), the data inputs are unclear, the outputs are difficult to interpret and the overall assessment is not based on a forward looking model of power flows. The impact assessment does not properly consider the potential outcomes for current and future customers. CMP213 and its alternatives do not, therefore, better facilitate Objective A. In our view, competition is likely to be more effective if the costs which parties impose on the system are properly reflected in the charges and therefore their decision making processes. We have seen no evidence that charging on the basis of load factor is more cost reflective than charging on the basis of capacity. Indeed, the evidence presented under CMP213 including work by the University of Bath would suggest that it is considerably less cost reflective than the current baseline. As stated in the University of Bath report there are three main reasons for this finding: • a generator's load factor is not a fixed parameter but varies throughout the year; • even for a given technology, load factor will vary according to location, congestion and efficiency (price of

	energy production); and • Congestion costs vary significantly across boundaries over time. Therefore, since CMP213 and its alternatives do not adequately address the main cost drivers for varying types of generation and output across the system they do not better facilitate Objective A. • **We consider that the load factor elements under CMP213 and its alternatives considerably weaken the long term investment signals provided by the current locational charging regime and cannot better meet Objective B**. Locational signals for low load factor generation in the GB electricity market are significantly weakened under CMP213. As set out above this change does not seem to be justified based on the analysis undertaken by the University of Bath. Consequently, CMP213 and its alternatives would appear to encourage connection of low load factor generation at the furthest periphery of the transmission system which would result in a corresponding increase in wider transmission investment, constraint costs and transmission losses. In contrast there appears to be a significant and material increase in locational charges for low load factor generators located in southern Britain which are closer to centres of demand and which tend to reduce overall transmission investment on the wider system, constraint costs and transmission charges. This significant shift in locational signals for similar classes of generation connected to the transmission system as a consequence of CMP213 and its alternatives illustrates its lack of cost reflectivity when compared with the current charging methodology. We note that the impact assessments included in the Consultation Document do not adequately explore the impact of the locational signals under CMP213 and its alternatives on generation and transmission investment. CMP213 and its alternatives do not, therefore, better facilitate Objective B. • **Capacity based charging regimes more accurately reflect the impact on individual parties on wider transmission investment (Objective B).** Charging should reflect the costs associated with full export of the power station at any time irrespective of load factor (i.e. it reflects firm transmission rights). However, CMP213 and its alternatives dampen the cost signals by taking into account historic load factors in determining wider charges rather than the capacity of the connection (and firm transmission rights) under the current baseline. In addition, all parties should face similar locational transmission charges that reflect the wider geographical distribution of costs of investment in transmission assets that meet the specific transmission capacity requirements alongside the costs of carbon, fuel, land, labour, resource availability and that this should promote competition overall. This includes negative transmission charges in areas where generation investment helps to reduce the overall costs of transmission investment. It is for the relevant security standards to determine the level of transmission build and not

	the charging regime. CMP213 and its alternatives do not, therefore, better facilitate Objective B. • **It is inappropriate to charge on the basis of a dual background (Objective B)**. CMP213 and its alternatives assert that they better reflect changes to the National Electricity Transmission Security and Quality of Supply Standards (NETSSQSS). However, the CMP213 methodology does not efficiently or effectively reflect the trade off between the year round and the security backgrounds in transmission charges that is adopted for transmission investment under the NETSSQSS. Although the NETSQSS is taken into account in relation to the wider background there is no direct link between the way that the load factors have been determined under CMP213 and its alternatives and the NETSSQSS standards because they would be based on historic load factors. CMP213 original takes an arbitrary approach in allocating transmission charges to each of these backgrounds. Consequently, CMP213 and its alternatives do not better reflect the dual background or the costs associated with transmission investment in the calculation of transmission charges as required under Objective B. • **We do not believe that CMP213 alternatives that support investment in HVDC links and island transmission investments can be justified on the basis of a discounted approach using arbitrary judgments (Objective B).** Cost reflective charges are required to justify HVDC links and island transmission investment. CMP213 alternatives based on arbitrary judgements do not better facilitate Objective B. • **We believe that CMP213 and its alternatives may not properly take account of the developments in transmission licensees' transmission businesses (Objective C)**. CMP213 and its alternatives add considerable complexity to the charging arrangements and may increase the volatility of charging. Consequently, it may be difficult for users to forecast transmission charges. This undermines locational signals and may give rise to inefficient transmission investment. CMP213 and its alternatives do not, therefore, better facilitate Objective C. Overall, we do not believe that CMP213 or any of the alternatives better facilitate the CUSC objectives. Consequently the status quo should be maintained since it optimises network efficiency on the basis of the cost reflective locational signals and firm transmission rights.

Do you support the proposed implementation approach? If not, please state why and provide an alternative	We continue to believe that further consideration of implementation dates is required given the need to complete the impact assessment of the original and the alternatives. The work should examine the likely effects of CMP213 and its alternatives on the GB electricity market including assessment of lead times

suggestion where possible.	for electricity power purchase arrangements and implementation of the proposed capacity mechanism and contract for differences. The impact on existing plant should be carefully assessed. Financial investment decisions based on the best available information at the time that those decisions were made will be undermined if transmission costs change substantially as a result of a significant change to the existing methodology. CMP213 and its alternatives may add considerable risk to the sector and will make it more difficult to make the case for funding for projects in future given the amount of perceived exposure to regulatory risk and even more so if transitional arrangements are not included. Analysis should also focus on the cost of CMP213 original or any of the alternatives to the end consumer. It should also consider the impacts on existing plant and costs to the industry. It would not be economically efficient to force premature closures as a result of financial investment decisions that were based on very difficult transmission cost levels. Once a full assessment is undertaken a decision on the methodology and appropriate implementation arrangements can be taken. Any significant change to the existing charging methodology will require a long lead time in order to allow suppliers to adjust their supply contracts and to allow generators to take differences in the charging methodology into account. Generators may need to reduce their TEC or be forced to close their plant and would need to provide sufficient notice to National Grid in order to do this. For projects in development this may be up to 4 years prior to commissioning. As noted in our response to the Workgroup consultation we support a transitional approach towards implementation of CMP213. Our preference is for a suitable lead time that would enable users to anticipate the proposed changes in their commercial arrangements This should as a minimum be two years from the start of the charging year (1st April) after the year in which an Ofgem decision is made to be consistent with hedging timescales in the electricity market. In addition transitional arrangements are required to enable existing generators with sunk investments to manage effectively the risks associated with the change over a number of years. This could be a gradual introduction of the new charges for qualifying generators over a minimum of five years after the implementation date.
Do you have any other comments?	As outlined above we do not support implementation of CMP213 or any if its alternatives as they do not better meet the CUSC

	objectives. We note that the impact assessment is incomplete and was presented by National late in the process with little time for any consideration. We have further concerns about the CUSC process including the following: • The working group does not appear to have completed its terms of reference with respect to the assessment of the impact of CMP213 and its alternatives on current and future consumers on a national and regional basis (terms of reference k) and complete an environmental analysis including an assessment of likely impact on electricity generation carbon intensity (terms of reference l); • The working group has not considered the effects of the proposals on different classes of users including the effect of undue discrimination and the potential for winners and losers; • The demand side impacts have not been assessed including the effect on customer bills; • The incentive properties of CMP213 and its alternatives to connect at distribution rather than transmission voltages has not been examined; and • The distributional effects of the proposal including the prospect of windfall gains or losses have not been considered at all.

CUSC Code Administrator Consultation Response Proforma

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Respondent:	*James Anderson, james.anderson@scottishpower.com*
Company Name:	*ScottishPower and Scottish Power Renewables*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.
	ScottishPower supports the sharing methodology contained within the Original Proposal and believes that combining this with

	proposals contained in Workgroup Alternative CUSC Modifications (WACMs) which align the charging of costs of HVDC transmission circuits with AC circuits would better meet the Applicable CUSC Charging Objectives [ACOs] as follows; **i. Sharing methodology** (a) The sharing methodologies proposed under the Original Proposal and to a lesser extent under Diversity 1 better reflect the impact on transmission investment costs from each generator's siting decision than the existing methodology and thus better facilitate competition and accordingly ACO (a). (b) The basis upon which transmission investment decisions are made was changed on the implementation of SQSS GSR009. The sharing methodologies proposed under the Original Proposal and Diversity 1 better reflect the investment costs which generators impose upon the transmission system given their operating pattern (as reflected by load factor) thus improving the cost reflectivity of TNUoS charges and better facilitating ACO (b) (c) By recognising National Grid's refinement of the transmission investment cost benefit analysis methodology (through SQSS GSR009), the proposed sharing methodologies take account of this development in the transmission business and reflects this in the Charging Methodology better facilitating ACO(c). The Original proposal is most closely aligned to GSR009 through its application of generator load factor. **ii. Treatment of HVDC** (a) The current charging methodology does not take account of the use of HVDC technology. By providing clarity on the treatment of HVDC circuits in the charging methodology, CMP213 will facilitate generator investment decisions and new entry and better facilitate competition [ACO (a)]. (b) Aligning the treatment of costs for HVDC circuits with AC circuits by excluding certain costs from the Expansion Factor calculation will ensure that HVDC circuits are treated in a consistent and cost reflective manner better facilitating ACO (b). (c) The current charging methodology does not take account of the use of HVDC technology. By incorporating the treatment of HVDC circuits in the charging methodology, CMP213 takes account of this development in the transmission business and reflects this in the

	Charging Methodology better facilitating ACO(c). **iii. Island Charging** (a) By clarifying the proposed charging method for Island generators, CMP213 better facilitates investment decisions by those proposing to develop generation in Island locations thus leading to new generation entry and better facilitating competition [ACO (a)]. (b) The proposed treatment of the transmission investment costs associated with Island generators in the charging methodology is consistent with the treatment of onshore generation and more cost reflective than the existing methodology and thus better facilitates ACO (b). (c) Developers are seeking to progress generation projects in order to exploit the abundant renewable resources available on Island locations. Clarifying the proposed treatment of these generators in the charging methodology better reflects this development in the transmission licensees' transmission businesses thus better facilitating ACO (c). The features of CMP213 Original and WACMs supported by ScottishPower, if implemented, help underpin wider energy policy objectives –accelerating deployment of low carbon generation, improving prospects for security of supply and ensuring costs remain affordable for consumers.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	In the Authority's Direction of 25 May 2012, industry was urged "to expedite this process and submit a final CUSC modification proposal report, with all the requisite justification and evidence, in a timely manner ***to ensure benefits are realised as quickly as possible***". With this in mind, ScottishPower believes that implementation should be in as short a timescale as practicable to realise those benefits and therefore supports ***Option (2) April 2014.*** Although conscious of the problems introduced by a mid-year tariff changes, should that date not be achievable, we would support ***Option (3) mid-year 2014/15***. ScottishPower would stress the importance of striving to achieve an implementation date of 1 April 2014 in order to reduce continued uncertainty over future TNUoS charges. Investors in GB's electricity industry are facing a great deal of

	change in the short to medium term (e.g. Banding reviews within the RO, implementation of EMR policies such as CfD and Capacity Market, EU Network Codes and GB Future Trading Arrangements). A number of workstreams underway to address these changes, including CMP213, with the objectives of decarbonisation, ensuring security of supply and delivery in the most cost effective manner to support domestic, commercial and industrial consumers. To support investment decisions and ensure no hiatus in deployment of generation, it is imperative that decisions and implementation are made in a timely manner with an appropriate allocation of risk being made to ensure delivery of low carbon investment at an efficient cost. Indicative tariffs have been published reflective of the various alternative methodologies considered by the Workgroup. As such we envisage that National Grid should be able to produce tariffs in line with the existing timetable following a prompt decision or “minded to” decision from the Authority.

Do you have any other comments?	Due to the large number of WACMs under CMP213, ScottishPower has considered its response regarding each of the three major areas detailed in the proposals (Sharing, HVDC and Islands). We have also analysed how these proposals reflect our opinion of whether the Original Proposal plus each of the Alternatives might better meet the Applicable CUSC Objectives. **Overview of SP Analysis of Proposals and Alternatives** The deployment of onshore wind resources should be maximised as this is the least cost form of renewable generation. Any displacement would require to be met by offshore wind as the next marginal cost technology pushing costs upward as outlined in Oxera’s report[1] Principles and Priorities for Transmission Charging Reform. The Oxera report highlights that “If the UK is able to meet its renewable targets, an additional 4TWh of onshore wind could displace 4TWh of relatively more expensive offshore wind. This implies that the associated annual saving through a reduction in the obligation size to meet the UK’s renewable target could be around £164m (in 2009 prices) in each year subsequent to the target being met.” In other words, TNUoS charging should not deter investment in low-carbon plant in high resource areas such as the peripheral areas of GB and

[1] Principles and Priorities for Transmission Charging Reform, Oxera, November 2010. http://www.ofgem.gov.uk/Networks/Trans/PT/WF/Documents1/Principles_and_Priorities_for_Tx_Charging_Reform_Oxera.pdf

	should recognise that a large number of large transmission investment projects will be dictated by regulatory processes separate from any signal from locational transmission priced. ScottishPower supports WACMs which combine the sharing methodologies developed under the Original Proposal when combined with a method of calculating HVDC Expansion Factors which is equitable with the treatment of AC circuits. Alternatives achieving this are highlighted in Figure 1 below. WACMs based upon Diversity Method 1 have considerable additional complexity due to the diversity calculation and do not constitute as significant an improvement on the Baseline as the Original sharing methodology. WACMs based upon Diversity Methods 2 and 3 are significantly less cost reflective than the Original sharing methodology and thus the additional complexity contained within either of these Diversity methodologies is not fully justified. We do not therefore believe overall that any of the WACMs based upon Diversity Methods 2 or 3 better meet the Applicable CUSC Objectives. In addition, analysis conducted in the CMP213 Impact Modelling Stage 2 results demonstrates that both the Original Proposal and the Original combined with HVDC cost allocation in line with AC circuits deliver a more cost effective outcome for energy consumers than the Diversity methodologies over the period to 2030. Expected consumer savings compared to Diversity Method 3 in particular imply a reduction in cost to an average consumer of up to £8.42 per year as summarised below. Methodology — Consumer saving £ p.a Average 2014 - 2030 Original — £8.42 Original HVDC 50% — £6.82 Diversity 1 — £1.33 Diversity 2 — £2.50 Diversity 3 — £0.01 **Sharing** The sharing methodologies developed under the Original Proposal (along with Alternatives based on the Original) and Diversity Method 1, better meet applicable Objectives (a) and (b) than the Baseline and better than Diversity Methods 2 and 3. The Original sharing methodology (along with Alternatives based on the Original) better meet the Applicable Objectives than Diversity Method 1. CMP213 aims to reflect the sharing of transmission network

	capacity by generators, which is assumed in the GB SQSS, into the Investment Cost Related Pricing (ICRP) TNUoS charging methodology. ScottishPower supports the use of an Annualised Load Factor (ALF) as a proxy for parameters which determine the assessment of the costs imposed by different generators on the electricity transmission network through the proxy of their load factors. ScottishPower believes that the Original proposal achieves the best compromise between cost-reflectivity and additional complexity in reflecting the differential impact of generators into the charging methodology. While the use of a dual background and scaling factors adds a level of complexity to the already complex existing charging model there are considerable benefits in improved cost-reflectivity. These benefits have been quantified in the CMP213 Working Group Report – Volume 2 (page 243) as demonstrating an overall reduction in Costs to Consumers from introduction of the Original charging methodology in the region of £10bn[2] over the period 2014-2030. In ScottishPower's opinion, the benefit of adding considerable additional levels of complexity through the use of a Sharing Factor has not been fully justified and we believe that the introduction of this into the methodology would greatly reduce the transparency and predictability of TNUoS tariffs thus making it less practical for developers to make efficient economic decisions. An individual generator's TNUoS charges would not only be subject to the siting decisions of other generators (as at present) but would be also vary according to the technology (carbon/low carbon) and load factor of those other generators. This would increase the complexity and uncertainty of forecasting TNUoS tariffs over the expected lifetime of a generation plant and lead to higher risk factors being included in investment decisions. Ultimately, the increased cost would be passed through to consumers. In particular, we do not believe that there has been sufficient evidence presented to support the assumption that optimum network capacity sharing can only be achieved when there is a perfect match between Carbon and Low-Carbon generation and the consequent "capping" of the Sharing Factor under Diversity methods 2 and 3 at 50%. Therefore, in our opinion both these methods are significantly less cost reflective than the Original or

[2] £10bn decrease in consumer bills relative to Status Quo is taken from supporting analysis to Annexe 15 provided to Workgroup on 4 April 2013; Impact Assessment Modelling Stage 2 Results.xls

	Diversity Method 1. Diversity Method 3, which applies the same tariffs to both intermittent and conventional plant irrespective of load factor, inherently fails to recognise the differing impact of individual generators upon investment in the transmission system. Diversity Method 3 does not reflect the methodology used by the Transmission Owners when making transmission investment decisions as reflected in the GB SQSS and is therefore less cost reflective than the other methodologies considered. In terms of cost to consumers, neither Diversity Methods 2 nor 3 provide the level of benefits to consumers enjoyed by the Original Proposal or the Original Proposal with 50% socialisation of HVDC converter station costs[3]. **Sharing - Hybrid or Historic Annualised Load Factor (ALF)** As stated above, ScottishPower supports the use of an Annualised Load Factor (ALF) as a proxy for the parameters which determine the assessment of the costs imposed by different generators on the electricity transmission network. We remain concerned, however that the historical methodology proposed for calculating ALF does not take sufficient account of factors which significantly change a controllable generator's future running pattern e.g. environmental legislation, extended outage (planned or unplanned due to breakdown), the trajectory of the carbon price support or other factors. We acknowledge that some types of low carbon generation (principally intermittent) are considerably less predictable and would support the use of ALF without reconciliation for these generators. We believe that the Workgroup has developed a workable methodology (the "Hybrid "approach) which would use controllable Generators' forecast load factors followed by reconciliation post year–end. Charging differences between forecast and actual usage values at 1.5 times the TNUoS rate would act as an incentive on generators to submit an accurate forecast and any over-recovery would be reallocated to all generation users via the Residual Charge. Use of the Hybrid ALF would better reflect generators' usage of the transmission system by allowing sudden changes in load

[3] Benefit to consumers versus Status Quo modelled as £10bn for Original, £7.5bn for Original plus HVDC but only £3.5bn and £0.1bn for Diversity 2 and 3 respectively. Figures from supporting analysis to Annexe 15 provided to Workgroup on 4 April 2013; Impact Assessment Modelling Stage 2 Results.xls

	factor to be reflected in TNUoS charges without the significant delay inherent in a 5 year average and would therefore be more cost reflective, better delivering efficiency in the costs passed to GB consumers. **HVDC** CMP213 reflects the introduction of HVDC transmission technology into the ICRP charging methodology where this is lacking at present thus better reflecting developments in the Transmission Licensees' transmission businesses. The existing DCLF ICRP Transport Model makes use of circuit impedance to calculate circuit flows. On the assumption that it is intended to continue to use the Transport Model, it will be necessary to calculate a notional impedance for the HVDC circuits in order to allocate a proportion of the energy flows to these circuits. We agree that the methodology proposed for calculating this notional impedance which calculates the desired flow across ***all*** the transmission boundaries that the HVDC circuit relieves bests reflects the economic justification for the investment in the HVDC circuit. ScottishPower believes that in order to achieve cost reflectivity at levels that are comparable with the treatment of onshore AC transmission elements in the ICRP methodology, the cost elements of HVDC converter stations which perform the same functions as AC transmission elements which are not included in the AC circuit Expansion Factors should be excluded from the HVDC methodology. The treatment of HVDC costs under the Original proposal is not equitable with the treatment of the costs of similar transmission elements on the AC system and therefore does not better meet Applicable Objective (a) as inequitable treatment cannot better facilitate competition. The various methods for allocating HVDC converter station costs all achieve more equitable treatment to various degrees than the Original proposal and therefore better meet Applicable Objective (a). Providing certainty and predictability of future TNUoS tariffs better facilitates future investment decisions by generators and therefore methodologies which codify in advance the proportions to be included in the Expansion Factors better facilitate Applicable Objective (b) than methods which derive from specific costs post construction. It is clear from the evidence presented to the Workgroup that a significant proportion of HVDC converter stations (approximately

	50%) perform the same functions as AC substations whose costs are recovered through the Residual element of the TNUoS charge and therefore the costs of these HVDC components should be excluded from the HVDC Expansion Factor. ScottishPower recommends that the generic percentage breakdown of HVDC converter costs identified at 5.24 to 5.28 should be used (50%). Avoiding the need to derive a specific percentage split for each HVDC converter station would improve predictability, reduce uncertainty in forecasting TNUoS tariffs and reduce complexity. To the extent that elements of the HVDC converter station replicate the function of AC components, such as substations and Quadrature Boosters, which are not charged locationally under the existing methodology, then equitable treatment dictates that the costs for these elements should also be excluded from the calculation of the Expansion Factor. The adoption of two separate generic percentages to reflect the difference in capability between Current Source Converter (CSC) (10%) and Voltage Source Converter (VSC) (20%) technology has been adequately justified in the evidence presented to the Workgroup [5.29 to 5.33 and Annexes 14.4 & 14.6] **Islands** CMP213 attempts to address the issue of the use of long transmission spurs to connect Island-based generators using relatively expensive transmission technologies including HVDC. It may not fully address the issues raised by island generation developers in terms of producing tariffs which encourage the extensive renewable resources available on island sites to be fully developed but it does result in a more cost reflective methodology and improved consistency with charges on the mainland. When calculating Expansion Factors for Island links, the treatment of HVDC elements should be consistent with that of HVDC circuits paralleling the onshore AC transmission system (bootstraps) i.e. the treatment of HVDC converter station cost elements should be consistent with that for bootstraps. The proposed changes to the definition of Local Circuits which would see Island connections treated as Local would address the issue where full redundancy is not provided in an island generator's connection by allowing the appropriate Security Factor to be applied [3.30]. We agree with the use of a Counter Correlation Factor to

	address the issue of sharing on radial circuits including those connecting island generators [3.29]. **Developments in transmission licensees' transmission businesses** The electricity industry is undergoing a period of significant change with the push to meet renewable electricity targets and the closure of existing thermal power stations driving the requirement for significant investment in electricity transmission infrastructure. At a more detailed level, the GB Security and Quality of Supply Standard (SQSS) has been updated (GSR 009) to reflect the new approach to determining the requirement for transmission investment on a cost-benefit basis. As the current TNUoS charging methodology is Investment Cost Related it is therefore necessary to update the charging methodology to reflect this new approach to transmission investment in the GB SQSS. In addition, it has been determined that HVDC technology should be deployed on the GB transmission system as a cost effective method of facilitating increased energy flows. As use of this technology is not currently reflected in the current charging methodology, changes to the methodology are required. To a varying extent, therefore, the Original Proposal plus the WACMs all better meet Applicable CUSC Objective C in that they take account of developments in transmission licensees' transmission businesses. **General** In reaching final conclusions on CMP213 it will be important to reflect on current developments at a European level, in particular the move towards a single Integrated Energy Market, the work being undertaken on new network codes which will be implemented in GB over the next few years, and developments to integrate energy infrastructure.

Figure 1
CMP213 Alternatives matrix

Main Components of CMP213	Original	1	2	3	4	5	6	7	9	12	14	16	17	18	19	21	22	23	24	25	26	28	30	31	32	33	40
								✔	✔	✔	✔	✔			✔	✔	✔	✔			✔	✔	✔			✔	✔
Extent of Sharing																											
No Diversity	x	x						x			x					x	x					x					
Diversity Method 1			x			x			x	x		x			x			x			x		x			x	x
Diversity Method 2				x			x						x						x					x			
Diversity Method 3					x									x						x					x		
Form of Sharing																											
YR - ALF historic specific (5 years)	x		x	x				x	x		x	x	x			x		x	x			x	x	x			
YR - Hybrid		x				x	x			x					x		x				x					x	x
Parallel HVDC																											
Specific EF 100% Conv+100%Cable (original)	x	x	x	x	x	x	x																				
Specific EF; generic 40% Conv+100%Cable (AC sub + QB)								x	x	x	x	x	x	x	x												
Specific EF; generic 50% Conv+100%Cable (AC sub)																						x	x	x	x	x	x
Specific EF; specific *x* % Conv. cost reduction (AC sub)																x	x	x	x	x	x						
Islands																											
Specific EF 100% Conv+100%Cable (original)	x	x	x	x	x	x	x																				
Specific EF; generic 30% Conv+100%Cable (AC sub + STATCOM)								x	x	x																	x
Specific EF; generic 50% Conv+100%Cable (AC sub)											x	x	x	x	x							x	x	x	x	x	
Specific EF; specific *x* % specific Conv. cost reduction (AC sub)																x	x	x	x	x	x						

x Features included in Alternative

✔ Alternatives which ScottishPower considers better meet the Applicable CUSC Objectives than the Baseline

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Catherine Birkbeck* *cbirkbeck@scottishrenewables.com*
Company Name:	*Scottish Renewables*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	Scottish Renewables has provided its views on the Original and Alternatives through its voting in the Working Group and justifications in the voting forms. For completeness, we voted for WACM number 7 as best overall, and we have not changed this view. Justifications against the main constituent parts of the Original and the WACM's are as follows: **Sharing – no diversity** Evidence base for ALF link to incremental constraint costs is strong, and a more consistent and long lasting relationship than other shorter term effects of bid price and diversity of plant in an area. Support no diversity overall as it improves cost reflectivity without excessive complexity and links variability in charges with variability in useage, which is manageable by generators. **Sharing – diversity method 1** Impact of diversity on incremental costs has been demonstrated in principle, but we are concerned that all Diversity methods whilst attempting to improve the resolution of cost signals (i.e. average ALF to more specific targeting on zones) require some subjective assumptions for what is a complex and changing picture, so improvement in accuracy is debateable at best. Furthermore, the variability of charges being linked to diversity cannot be managed by generators as they have no control over where other generators locate. Of the three methods, Diversity

	method 1 employs LC/C assumptions but does not cap sharing at 50% (see Diversity 2 for comment on this), and it also avoids any on/off sharing signals for boundaries. On that basis, Diversity 1 is considered to be an improvement on the baseline *but not an improvement on options with no diversity*. **Sharing – diversity method 2** Methods 2 and 3 Diversity rather arbitrarily limit sharing at 50%, for which there is no empirical evidence. Therefore we feel strongly that it is a step too far and requires more evidence. **Sharing – diversity method 3** As Diversity 2 **Form of sharing – ALF 5 year historic** Transparent, employs user data and practical **Form of sharing – hybrid** Less practical to implement than historic ALF. **Parallel HVDC and islands – Specific expansion factor (EF) targeting 100% of Converter costs** Targeting 100% of the costs locationally is inequitable with cost allocation in existing mainland expansion factors, and inconsistent with TNUoS principles which do not target fixed costs. **Parallel HVDC and islands – Specific EF, Generic 40% targeting of Converter costs for AC substation equivalence and Quad Booster-like benefits** Removing these costs achieves better parity with existing expansion factors and is more consistent with the TNUoS methodology. **Parallel HVDC and islands – Specific EF, generic 50% targeting of converter costs for AC substation equivalence** Whilst this option does recognise equivalence on treatment of AC substations it does not attempt to target other fixed costs in the AC system. **Parallel HVDC and islands – Specific EF, target according to**

	removal of the exact cost of AC equivalent costs in each converter station As above, although recognise enhanced cost reflectivity of specific treatment, suspect cost breakdown will not be practicable to obtain.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	In terms of implementation date, we favour a 1 April 2014 implementation date, which, we note, is already delayed from the original Project TransmiT timetable. SR recognises that this could be difficult to respond to for parties for whom the altered charges materially altered project economics. But, SR ask that individual generators make detailed arguments to Ofgem on their individual commercial impacts, and Ofgem weigh up the delay in benefits from delayed implementation against the nature and scale of the disbenefits to individual parties on a one-off basis. We do not wish implementation to be delayed for one or two players, and hope the impact could be managed on a case-by-case basis.
Do you have any other comments?	SR notes the publication of impact assessment results in the Code Administrator consultation. This information has been useful and we acknowledge the work that National Grid has put into producing these results for the Code Administrator consultation. Whilst we feel that the results are sufficient to understand the broad direction of travel of impacts, we do feel that the results would be enhanced by some commentary for those parties interested in interpreting the results in the context of the modelling methodology. We welcome National Grid's commitment to do this via their own response to the Code Administrator consultation, and would welcome the opportunity for any clarifications arising via TCMF or some other informal forum, before Ofgem's own impact assessment.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Garth Graham (garth.graham@sse.com)*
Company Name:	*SSE*
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC objectives are:* ***Use of System Charging Methodology*** *(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;* *(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);* *(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.* We have considered carefully the CMP213 Code Administrator consultation documentation, i.e. the four volumes, as part of our deliberations with respect to whether we believe the CMP213

	Original and the associated WACMs better facilitate the Applicable CUSC (charging) Objectives. We provide a summary below of our views and have provided our detailed reasoning in the form of a separate Annex (1) and a separate Annex (2) which is an integral part of this response and should be read alongside this question. **Summary of Annex (3)** We have considered, in detail, each of the main applicable component elements of CMP213 Original and the WACMs in terms of better meeting the applicable (charging) objectives, and these are set out in Annex (3). Our reasoning, at a high level, as to why certain elements are better include:- No Diversity: (a) better reflects the costs of using the transmission system onto those who give rise to those costs, by being based on usage of that network at Peak and Year Round, which *facilitates effective competition*; (b) links TNUoS charges to the use of the transmission system at both the Peak and also Year Round so better *reflects the costs* of the transmission system onto Users; and (c) transmission businesses are developed in line with the GB SQSS and the approach to sharing outlined in the CMP213 Original, i.e. no diversity, reflect this, so best matches the *developments in the transmission licensees' transmission businesses.* Year Round ALF historic specific (5 year): (a) better reflects Users' usage, based on the Users' actual ALF, of the transmission system which better *facilitates competition* in generation of electricity; and (b) Having a 'usage' element, based on the Users' actual ALF reflected in TNUoS charges better reflect Users usage of the transmission system and better *reflects the cost* of using the transmission system onto those that give rise to those costs. Year Round Hybrid: (a) In addition to the benefits associated with the Year Round ALF historic specific (see above) the Hybrid option (by providing Users with the ability, if they wish, to provide their own forecast ALF) is an enhancement which better *facilitates competition* in generation of electricity as it allows Users (if they wish) to better reflect changing market conditions; (b) In addition to the benefits associated with the Year Round

	ALF historic specific (see above) the Hybrid option (by providing Users with the ability, if they wish, to provide their own forecast allows the cost of Users expected usage, of the transmission system, to be taken into account (with a mechanism to ensure those forecasts are reasonable) and this, therefore, better *reflects the cost* of using the transmission system onto those that give rise to those costs. [HVDC] Specific EF; (i) generic 40% Conv+100%Cable (AC sub + QB) & (ii) generic 50% Conv+100%Cable (AC sub) & (iii) specific *x*% Conv. cost reduction (AC sub) (a) As the non-locational TNUoS charge includes items that should be recovered non-locationally (see (b) below) this is *beneficial to competition* in generation; (b) By reflecting a proportion of the convertor station costs and, if applicable, the QB costs into the non-locational TNUoS charge this better *reflects the cost* of these items on those that give rise to them in a similar manner to how those costs are treated on the equivalent (onshore) AC parts of the transmission system; and (c) Given the development of the business of the TO(s), in terms of the emergence of HVDC transmission circuits, this approach to the HVDC expansion factor better *matches the developments in the transmission licensees' transmission businesses* . [Islands] Specific EF; (i) generic 30% Conv+100%Cable (AC sub + STATCOM) & (ii) generic 50% Conv+100%Cable (AC sub) & (iii) specific *x*% specific Conv. cost reduction (AC sub) (a) As the non-locational TNUoS charge includes items that should be recovered non-locationally (see (b) below) this is *beneficial to competition* in generation; (b) By reflecting a proportion of the convertor station costs and, if applicable, the STATCOM costs into the non-locational TNUoS charge this better *reflects the cost* of these items on those that give rise to them in a similar manner to how those costs are treated on the equivalent (onshore) AC parts of the transmission system; and (c) Given the development of the business of the TO(s), in terms of the emergence of HVDC transmission circuits, this approach to the HVDC expansion factor does better *match the developments in the transmission licensees' transmission businesses* . **Voting Preference** Having considered, in detail, the consultation documentation and set out our detailed reasoning in Annex (3) and explored further, in Annex (2) some additional matters, we provide below (in tables 1 and 2) a high level summary of our views with respect to

	whether we believe the CMP213 Original and the associated WACMs **better** facilitate each of the Applicable CUSC (charging) Objectives, and overall, as compared to the Baseline (vote 1) and compared to the Original (vote 2). Whilst we are not required to give a view as to which is '*best*' we would note that WACM7 is, overall, the most suitable of the options that we believe better meet the Applicable CUSC (charging) Objectives (those options being the Original and WACMs 1, 7, 14, 21, 22 and 28 only).

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We have carefully considered the proposed implementation approach as set out in Section 9 of the consultation document and have provided, in a separate Annex (1), our detailed reasoning. **Summary of Annex (1) IMPLEMENTATION** We believe that, whilst all four implementation options (set out in Section 9, Volume 1) are 'practical', delaying the implementation of CMP213 Original (or WACM) would result in the benefits of this change not being realised. This would, in turn, lead to 'windfall gains & losses' as those Users for whom the change would not be beneficial would receive a windfall gain (from the delayed implementation) whilst those Users and consumer for whom the change would be beneficial would incur a windfall loss (from the delayed implementation). We therefore support the earliest implementation date including, for the avoidance of doubt, a 'mid-year' tariff change as, in our view, parties have had considerable foresight, over many years, firstly that a change to generator TNUoS was likely and, secondly, the broad level and nature of that change - initially via the Redpoint analysis (as part of the Ofgem Project Transmit work) and then, subsequently, via the analysis[1] that accompanies this CMP213 Code Administrator consultation (Annex 15, Volume 2). It seems unreasonable that parties forewarned of the potential change to generator TNUoS cannot deal with a 'mid year' change, given that the quantum of change to them in £ terms is

[1] We note the comments (in paragraph 7.6, Volume 1) that "In order to ensure a robust evidence base for the CMP213 Modification proposal National Grid has employed the same Redpoint models previously developed as part of the transmission charging Significant Code Review under Project TransmiT, and utilised them for the quantitative assessment of CMP213". This consistency of approach is welcomed as it ensures users have been provided with indicative tariffs on a consistent basis from the Redpoint (in late 2011) and the CUSC (in spring 2013) processes whilst the data sources have been undated (Table 21, Volume 1).

	orders of magnitude lower than credible changes to other costs such as fuel. In summary, we believe that the case for change has been made, that change has been widely trailed to all parties (giving them time to prepare accordingly) and, therefore, that implementation of CMP213 should occur as soon as possible after an Authority decision (including, for the avoidance of doubt, 'mid year' during this current (13/14) charging year) and, in any event, should be implemented on 1st April 2014 at the very latest.
Do you have any other comments?	We do have additional comments, with respect to CMP213 Original and the WACMs. Our comments centre on five main areas, each of which is explored, in more detail, separately in Annex (2), namely:- a) Customer Impact; b) Diversity; c) HVDC; d) Islands; and e) Ofgem Direction / Project Transmit aims. **Summary of Annex (2)** a) Customer Impact It is clear to us, given that the renewable and emission targets are met with all the options modelled (and thus *arrangements are in place that facilitate the timely move to a low carbon energy sector*) that two of the options (Original - total saving to each consumer £151 - and Original with 50% HVDC Convertors - £124 saving per consumer) show the greatest *value for money to existing and future consumers* and are, in our view, the most beneficial of the CMP213 implementation options (the Original and any of the WACMs). Of these, the Original is 'best' in terms of *value for money to existing and future consumers.* b) Diversity In summary, the CMP213 Original proposal provides, in our view, a very good balance between being relatively simple and easy to understand whilst being appropriately cost-reflective and not unduly discriminatory or confusing (particularly for smaller parties). In stark contrast the three Diversity methods deliver the worst combination of simplicity and cost-reflectivity, since they are more complicated and difficult to understand or forecast / plan operations to (particularly for smaller parties) than the CMP213 Original and also will be less cost-reflective (of the transmission

	system designed / built or operated, day-to-day) and result in discrimination against low load factor plant. In an attempt to take account of Diversity, the three Diversity methods have made simplifying assumptions which grossly understate generation sharing in transmission charging zones with a high proportion of low carbon generation and take no account, for example, of bid prices from demand side response in that zone. c) HVDC Having considered the various options and differing approaches associated with the treatment of HVDC transmission circuits we have concluded that the evidence is overwhelming that elements of the HVDC convertor stations are equivalent to AC elements of the transmission system (which are, under the current CUSC charging methodology, charged 'socially' rather than 'locationally'). These reasons also apply to the 'QB' type benefits that HVDC links provide to the operation of the system and, therefore, this QB benefit should be treated in a similar manner, as the AC equivalent, for HVDC links. It therefore follows that it would not be either cost-reflective or better for competition (in generation) if the TNUoS charges, for those (AC) equivalent elements of HVDC links, were not also charged, socially (rather than, as proposed, fully locationally). Given this we agree that the following three 'options' should be taken forward and (in one form or another) be incorporated into the CMP213 implemented solution. These three 'options' are:- i) Remove 50% of the (HVDC) converter station costs based on elements similar to AC substations; ii) Remove 60% of the (HVDC) converter station costs based on elements similar to AC substations and controllability similar to QBs; and iii) Remove a specific percentage of the (HVDC) converter station costs based on elements similar to AC substations. In light of this we support, in principle, all the WACMs with these elements. However, these benefits (in terms of better cost reflectivity, facilitating competition and reflecting changes in the transmission business) do not outweigh the far larger dis-benefits associated with Diversity methods 1-3 (and, therefore, we do not support any WACMs with Diversity 1-3, even if they include these HVDC 'options').

	d) Islands We have provided under ‘HVDC’ above our reasons as to why we support the removal of some HVDC convertor station costs. For the avoidance of doubt, those reasons associated with HVDC are also applicable here for islands. In terms of the matter of the voltage source convertors (VSCs) which are explored in the consultation document (pg75-76, Volume 1) and Annexes 14.4 and 14.6 (Volume 2) our view is that the benefits associated with QBs (see our detailed comments in Annex 3) also apply to VSCs as they too are beneficial in terms of transmission system operation, and therefore the costs of VSCs should be removed in a similar manner as QBs, i.e. 20% for VSC / 10% for QBs. e) Ofgem Direction / Project Transmit aims We believe that a number of the WACMs have component elements which are not only *worse* (in terms of the applicable CUSC objectives) but also run counter to the aims of the Project Transmit and / or the Authority’s Direction and would, in our view, be a gross distortion of the process (and call into question the viability of the ‘SCR’ process) if a WACM were to be implemented which so demonstrably ran counter to the Direction. Specifically, the WACMs including sharing in terms of Diversity 1 to 3 are not consistent with the GB SQSS approach to transmission investment planning undertaken by the TO(s) when actually building new (or expanding / enhancing) transmission circuits, and its clear that Diversity 3, with its single background, runs directly counter to the dual background approach set out in Project Transmit and the Direction. Finally, with respect to Diversity 3, it would, in our view, be a total travesty of the SCR process if, after some three years of detailed investigation we ended up, to all intents and purpose, back where we started with a TEC based (100% ALF) approach to TNUoS charging for GB generators.

TABLE 1 VOTE ONE – BETTER THAN BASELINE

Proposal	Objective (a)	Objective (b)	Objective (c)	Overall
Original	Better	Better	Better	**Better**
WACM 1	Better	Better	Better	**Better**
WACM 2	*Worse*	Neutral	*Worse*	*Worse*
WACM 3	*Worse*	*Worse*	*Worse*	*Worse*
WACM 4	*Worse*	*Worse*	*Worse*	*Worse*
WACM 5	*Worse*	Neutral	*Worse*	*Worse*
WACM 6	*Worse*	*Worse*	*Worse*	*Worse*
WACM 7	Better	Better	Better	**Better**
WACM 9	*Worse*	Neutral	*Worse*	*Worse*
WACM 12	*Worse*	Neutral	*Worse*	*Worse*
WACM 14	Better	Better	Better	**Better**
WACM 16	*Worse*	Neutral	*Worse*	*Worse*
WACM 17	*Worse*	*Worse*	*Worse*	*Worse*
WACM 18	*Worse*	*Worse*	*Worse*	*Worse*
WACM 19	*Worse*	Neutral	*Worse*	*Worse*
WACM 21	Better	Better	Better	**Better**
WACM 22	Better	Better	Better	**Better**
WACM 23	*Worse*	Neutral	*Worse*	*Worse*
WACM 24	*Worse*	*Worse*	*Worse*	*Worse*
WACM 25	*Worse*	*Worse*	*Worse*	*Worse*
WACM 26	*Worse*	Neutral	*Worse*	*Worse*
WACM 28	Better	Better	Better	**Better**
WACM 30	*Worse*	Neutral	*Worse*	*Worse*
WACM 31	*Worse*	*Worse*	*Worse*	*Worse*
WACM 32	*Worse*	*Worse*	*Worse*	*Worse*
WACM 33	*Worse*	Neutral	*Worse*	*Worse*
WACM 40	*Worse*	Neutral	*Worse*	*Worse*

TABLE 2 VOTE TWO – BETTER THAN ORIGINAL

Proposal	Objective (a)	Objective (b)	Objective (c)	Overall
Baseline	*Worse*	*Worse*	*Worse*	*Worse*
WACM 1	Better	Better	Better	**Better**
WACM 2	*Worse*	Neutral	*Worse*	*Worse*
WACM 3	*Worse*	*Worse*	*Worse*	*Worse*
WACM 4	*Worse*	*Worse*	*Worse*	*Worse*
WACM 5	*Worse*	Neutral	*Worse*	*Worse*
WACM 6	*Worse*	*Worse*	*Worse*	*Worse*
WACM 7	Better	Better	Better	**Better**
WACM 9	*Worse*	Neutral	*Worse*	*Worse*
WACM 12	*Worse*	Neutral	*Worse*	*Worse*
WACM 14	Better	Better	Better	**Better**
WACM 16	*Worse*	Neutral	*Worse*	*Worse*
WACM 17	*Worse*	*Worse*	*Worse*	*Worse*
WACM 18	*Worse*	*Worse*	*Worse*	*Worse*
WACM 19	*Worse*	Neutral	*Worse*	*Worse*
WACM 21	Better	Better	Better	**Better**
WACM 22	Better	Better	Better	**Better**
WACM 23	*Worse*	Neutral	*Worse*	*Worse*
WACM 24	*Worse*	*Worse*	*Worse*	*Worse*
WACM 25	*Worse*	*Worse*	*Worse*	*Worse*
WACM 26	*Worse*	Neutral	*Worse*	*Worse*
WACM 28	Better	Better	Better	**Better**
WACM 30	*Worse*	Neutral	*Worse*	*Worse*
WACM 31	*Worse*	*Worse*	*Worse*	*Worse*
WACM 32	*Worse*	*Worse*	*Worse*	*Worse*
WACM 33	*Worse*	Neutral	*Worse*	*Worse*
WACM 40	*Worse*	Neutral	*Worse*	*Worse*

Annex (1) – IMPLEMENTATION : SSE detailed reasoning on CMP213 Original and WACMs Implementation

Summary

In our view Users, especially those with generation assets, who will be directly affected by the CMP213 associated changes to TNUoS have had sufficient time to factor any potential change into their normal day-to-day risks as the potential Project Transmit / CMP213 change has been well intimated.

We therefore believe that CMP213 Original (or any WACM) should be implemented at the earliest practical opportunity so that the demonstrable benefits of moving to a more cost-reflective transmission charging regime can be realised and passed on to end consumers. This, in our view, means Option (1) is the best implementation approach, with Option (2) the next best, Option (3) the following best. Option (4) is the least preferred implementation date as it is wholly inappropriate as it fails to meet the Authority's Direction requirements as regards implementation in a "*timely manner*"... "*to ensure benefits are realised as quickly as possible"* .

Any delay in implementation would in most scenarios result in the loss of a reduction in average consumer bills as modelled in the Impact Assessment as shown in figure A15.25, p243 of about £3 per consumer in 2014.

We believe that whilst all four implementation options (set out in Section 9, Volume 1) are 'practical' that to unduly delay the implementation of CMP213 Original (or WACM) would result in the benefits of this change not being realised which would, in turn, lead to 'windfall gains & losses' as those Users for whom the change would not be beneficial would receive a windfall gain (from the delayed implementation) whilst those Users and consumers for whom the change would be beneficial would incur a windfall loss (from the delayed implementation).

We therefore support the earliest implementation date including, for the avoidance of doubt, a 'mid-year' tariff change as, in our view, parties have had considerable foresight, over many years, firstly that a change to generator TNUoS was likely and, secondly, the broad level and nature of that change - initially via the Redpoint analysis (as part of the Ofgem Project Transmit work) and then, subsequently, via the analysis[2] that accompanies this CMP213 Code Administrator consultation (Annex 15, Volume 2).

Given the huge volatility in for example the cost of fuel it seems unreasonable that parties forewarned of the potential change to generator TNUoS, the quantum of which to them in £ terms is orders of magnitude higher than any credible change to their TNUoS tariff, cannot deal with a 'mid year' change.

In summary we believe that the case for change has been made, that change has been widely trailed to all parties (giving them time to prepare accordingly) and, therefore, that

[2] We note the comments (in paragraph 7.6, Volume 1) that "In order to ensure a robust evidence base for the CMP213 Modification proposal National Grid has employed the same Redpoint models previously developed as part of the transmission charging Significant Code Review under Project TransmiT, and utilised them for the quantitative assessment of CMP213". This consistency of approach is welcomed as it ensures users have been provided with indicative tariffs on a consistent basis from the Redpoint (in late 2011) and the CUSC (in spring 2013) processes whilst the data sources have been undated (Table 21, Volume 1).

implementation of CMP213 should occur as soon as possible after an Authority decision (including, for the avoidance of doubt, 'mid year' during this current (13/14) charging year) and, in any event, should be implemented on 1st April 2014 at the very latest.

Introduction

In coming to our view with respect to the implementation date for CMP213 (the Original or the WACMs) we have considered, in particular, (i) the CMP213 Code Administrator consultation document (ii) the Project Transmit Technical Working Group[3] reports and (iii) the associated statements, etc., from the Authority.

For example, we note the Authority Direction issued to National Grid and in particular the comments in the covering letter[4], of 25th May 2012, that:-

"Industry will decide the manner and timing of the industry process, but we continue to urge industry to expedite this process and submit a final CUSC modification proposal report, with all the requisite justification and evidence, in a timely manner to ensure benefits are realised as quickly as possible."

In our view the industry has been aware of the possibility of a substantial change to the basis on which TNUoS tariffs are calculated since at least September 2010. For example, the initial Project Transmit SCR Call for Evidence was published[5] on 22nd September 2010 and concluded, with a direction to National Grid, on 25th May 2012.

We also note that Ofgem has been seeking the expeditious implementation of a long term solution to TNUoS charging associated with its Project Transmit since its inception. Ofgem has made a number of Ofgem statements referring to a possible implementation date of 1st April 2012, for example:

i) Ofgem 'Project Transmit: approach to electricity transmission charging work' letter 27th May 2011[6]

"If appropriate, we aim to implement any change to TNUoS in time for the next charging year, i.e. from April 2012."

ii) Ofgem Project Transmit Stakeholder event 11th August 2011 'Opening Presentation' (slide 4)[7]

"*New Charges Target Date Apr 12*"

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[3] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=166&refer=Networks/Trans/PT/WF

[4]

http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20SCR%20cover%20letter%2025%20May.pdf

[5] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/PT[6]
http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf

[6] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf

[7] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Ofgem%20opening%20presentation.pdf

iii) Ofgem Project Transmit Stakeholder event 11th August 2011 'Closing Presentation' (slide 2)[8]

'Implementation'

•*Initiate CUSC process and NGET 2012/13 tariff development –December 2011*

•*Aiming for change, if appropriate, by April 2012–feasibility to be discussed at WG and through consultation process*

•*Ultimately, industry will decide the manner and timing of implementation*

iv) Ofgem 'Project Transmit: electricity transmission charging Significant Code Review update' 9th September 2011[9]

"...*Implementation of any change, if appropriate, would therefore be after April 2012, the potential implementation date we identified previously*."

Approach

In considering how CMP213 Original (and any WACM) would be implemented along with (if appropriate) any associated transitional arrangements we have taken account of the deliberations of the Project Transmit Technical Working Group on 'Implementation / Transitional Issues' as set out in section 10 of their report[10] from approximately 18 months ago, e.g. it was prior to the details associated with CMP213 being known / worked up and included the possibility of a Socialised ('postage stamp') approach - which would have impacted directly on demand TNUOs charges, something which the CMP213 potential solution (be it the Original or any of the WACMs) will not do and therefore removes the need to delay implementation to accommodate changes to supply supply customer tariffs.

We agree with the CMP213 Workgroup (as set out in paragraph 9.14) that there are four options for implementing CMP213 Original (and any WACM), namely:-

1) 'mid year' during the 2013/2014 TNUoS Charging Year; or
2) 1st April 2014; or
3) 'mid year' during the 2014/2015 TNUoS Charging Year; or
4) 1st April 2015.

Impact on Demand

In terms of the impact on Users we have noted that any change to TNUoS tariffs should only directly impact on the allocation of TNUoS between individual generators as, with the 25th May 2012 Direction issued by the Authority, the demand TNUoS tariffs are to be based on the existing ('Status Quo') ICRP arrangements. Therefore we consider that there will be no direct impact of implementing CMP213 Original (and any WACM) on Consumers. Given this

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[8] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Ofgem%20closing%20presentation.pdf
[9] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=151&refer=Networks/Trans/PT
[10] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=166&refer=Networks/Trans/PT/WF

we believe there is no reason, on the ground of consumer impact(s), to unduly delay the implementation of CMP213 Original (and any WACM).

Rather we believe the reverse to be true. Figure A15.25 (on page 243 of Volume 2) "Change in average consumer bill[s] from status quo" clearly demonstrates there are, with some of the options, significant annual savings to consumer bills. For example, all years modelled show savings for consumers for CMP213 Original with 50% HVDC convertor station costs socialised (£124 saving per consumer) and consumer savings for all bar two years out to 2030 with CMP213 Original (with those two years showing only modest detrimental impacts, compared with substantially larger savings for consumers in the other years modelled, with a total saving to each consumer of £151). In contrast the WACMs with Diversity all show higher consumer bills, from early / mid 2020's onwards.

Therefore the sooner that TNUoS charges are made more fully cost-reflective (by implementing CMP213 Original or WACM 1, 7, 14, 21, 22 or 28) the sooner the benefits (of more cost-reflective charges) in terms of (a) improved competition in the generation (and supply) of electricity and, in the case of the non Diversity WACMs[11], (b) lower bills for consumers.

Timeline

In considering when CMP213 Original (and any WACM) can be implemented we have been mindful, going forward from now, of the stages still to go in the process and the potential timeline for these further stages. We note that the CUSC Panel vote is expected to take place at the end of May 2013, leading to a Final Modification Report being submitted to the Authority early in June.

It is our understanding, given the amount of work it has already undertaken as part of Project Transmit on this policy area, together with its active engagement in the CMP213 Workgroup deliberations, that the Authority may be in a position to undertake a Regulatory Impact Assessment (around its 'minded to' decision) in July for a period of consultation (possibly concluding in late August / early September).

Allowing for the Authority to carefully consider all the information provided (both as part of the CUSC process and its own Regulatory Impact Assessment process) and come to its reasoned conclusion it would, in our view, be possible for a final decision to be forthcoming from the Authority in September.

This, in our view, means that it is perfectly possible for the implementation of CMP213 Original (and any WACM) to be by 1st April 2014; i.e. from the start of charging year 2014/15 at the latest; which would still see National Grid meeting its 'traditional' pre-Christmas timescale for producing draft 'indicative' TNUoS tariffs, with the final tariffs being produced by the end of January 2014, for application from 1st April 2014 (at the latest).

Given the clear statement from the Authority (in its 25th May 2012 Direction letter) with respect "*to ensure benefits are realised as quickly as possible*" we believe that there is a strong argument, in this particular case, for the Authority to authorise National Grid (if

[11] i.e. WACMs 1, 7, 14, 21, 22 and 28.

necessary) to undertake preparatory work on generation TNUoS tariffs prior to an Authority decision, noting that similar 'pre-approval' work had been undertaken by National Grid on the Transmission Access Review (TAR) modification proposals during late 2008/early 2009 (prior to an Authority decision).

Implementation options

Option (1)

In respect of option (1) ('mid year') we agree with the CMP213 Workgroup (paragraph 9.15) that this does not necessarily mean exactly midway or halfway through the 2013/14 Charging Year; i.e. 1st October 2014 (or 1st October 2015 with option (3)); rather it could occur at any point during the Charging Year. There has already been one previous example of a 'mid year' TNUoS change and this had actually been put into effect on 1st December (2010)[12]. In our view a 'mid year' change in generation TNUoS tariffs is fairly straightforward and indeed has already been done before (in December 2010) so, from a practical perspective, it can be achieved (with respect to implementing CMP213 Original or any WACM) in the future.

We did consider the Project Transmit Technical Working Group deliberations (in paragraphs 10.12 and 10.13 of their report) with respect to 'mid year' implementation and were mindful that their consideration of this matter was in the context of (a) Improved ICRP and (crucially) (b) Socialised ('postage stamp') together with the 'Status Quo'. We note that had the Socialised approach been taken forward (it was ruled out by the Authority in its Project Transmit conclusions) then it would have impacted substantially on Supplier (and thus end consumer) TNUoS tariffs, which would have precluded a 'mid year' tariff change in that case. This therefore means, in our view, that the arguments set out in paragraph 10.12 (of the Project Transmit Technical Working Group report) are less relevant for the implementation of CMP213 and, therefore, a 'mid year' change is possible and practical.

One of the arguments against a 'mid year' tariff change has been that this would impact on Users in terms of their own budget for their power station. However, in this respect, we note that the amount of funds to be recovered, via the (27%) generation TNUoS tariffs, is fixed so any budget changes should be equal and opposite overall across all generation Users. In addition, Users today face other cost variances during a Charging Year; the most obvious of which is fuel (the cost of which can change on a daily basis), which are far greater than their TNUoS charges.

Therefore, in our view, the cost implications associated with the 'mid year' implementation of CMP213 Original (or any WACM) is small relative to the benefits that arise from its timely and expeditious introduction as it ensures that a fairer, more cost-reflective allocation is achieved at the earliest practical opportunity in line with the Authority's 25th May 2012 Direction letter. Furthermore, as we have noted above, the possibility of a change to TNUoS arising from the Project Transmit process has been well signposted to all Users since the autumn of 2010. In addition, as noted above, it would be possible for the Authority to authorise National Grid (if necessary) to undertake 'pre-approval' preparatory work on

[12] http://www.nationalgrid.com/NR/rdonlyres/11407548-92EE-485B-9A1C-5DBFAAD17F42/43351/NoticeofFINALtariffs.pdf

generation TNUoS tariffs prior to an Authority decision which would facilitate a 'mid-year' change based on option (1) by providing Users with additional notice of the TNUoS changes. Therefore, in contrast to the position noted in paragraph 9.20, we believe that the balance of arguments supports a 'mid year' implementation date for CMP213 Original (or any WACM).

Option (2)

We have noted that the Project Transmit Technical Working Group[13] (paragraph 10.7) *"....considered what a reasonable lead time for implementation might be and agreed that, were Ofgem to conclude on the SCR in its proposed timescales, an appropriate time to implement any new arrangements would be from April 2014."*

As we noted above, in option (1), it is perfectly feasible to implement a 'mid year' tariff change in Charging Year 2013/14, which could also involve, if necessary, (as noted under option (1) above) 'pre-approval' work being undertaken by National Grid on generation TNUoS tariffs prior to an Authority decision.

Given this, we consider that it therefore follows that it is perfectly feasible to implement changes to generation TNUoS tariffs arising from CMP213 (if approved) from the 1st April 2014.

Option (3)

This option would be the same as option (1) except it would occur sometime during the following Charging Year; i.e. from 1st April 2014 to 31st March 2015, and could also involve, if necessary, (as noted under option (1) above) 'pre-approval' work being undertaken by National Grid on generation TNUoS tariffs prior to an Authority decision.

Option (4)

Having considered the preceding three options it therefore follows that it would, in our view, clearly be feasible to implement CMP213 Original (or any WACM) from 1st April 2015.

However, we believe in light of the Authority's Project Transmit SCR Direction letter of 25th May 2012 about acting in a "*timely manner*" and "*to ensure benefits are realised as quickly as possible"* that it would be wholly inappropriate to unduly delay the benefits associated with CMP213 (if approved by the Authority) by postponing the implementation of CMP213 until 1st April 2015.

Transition options

We welcome the fact that the CMP213 Workgroup has considered a number of potential transitional arrangements (as set out in Section 9 of the consultation document) and we concur, in particular, with the point made in paragraph 9.39 that Users have been aware of this change for some considerable time (possibly in excess of three years).

[13] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=166&refer=Networks/Trans/PT/WF

We have considered the two broad options set out in Section 9 of the consultation document regarding (i) the TEC reduction options and (ii) Grandfathering. With respect to the TEC reduction options we concur with the CMP213 Workgroup members who believe such approaches (full TEC or a range of TEC reduction) would be discriminatory. With respect to the suggested Optional Grandfathering approach we find it hard to comprehend how such an approach could ever be considered fair, reasonable or non discriminatory given, for example, the suggested cost (~£100M – see paragraph 9.54 – which is approximately a third of the total TNUoS to be recovered from generation Users per year) and associated complexity (as set out in paragraph 9.55) its implementation would involve.

Furthermore, it seems that the supporters of this approach are seeking to 'have their cake, and eat it'. They seek to lock in (in perpetuity) all the 'benefits' of not paying cost-reflective transmission charges[14] whilst, at the same time, not seeking to 'grandfather' themselves into the existing regime with respect to for example the new market / industry changes that are forthcoming such as the EMR Capacity Mechanism, access to the EMR CfD regime etc. No arguments are put forward by those same parties who seek an undue delay in the implementation of CMP213 for a similar delay in the implementation of those changes being developed by the UK Government as regards, for example, the EMR Capacity Mechanism, access to the EMR CfD regime etc.. It seems that where a change is 'negative' to them those parties have 'huge problems' in, for example, planning or performing their normal day-to-day risk management and mitigation measure. However, those same 'huge problems' (if they exist?) seem to disappear very quickly whenever a change that is 'positive' to them is planned.

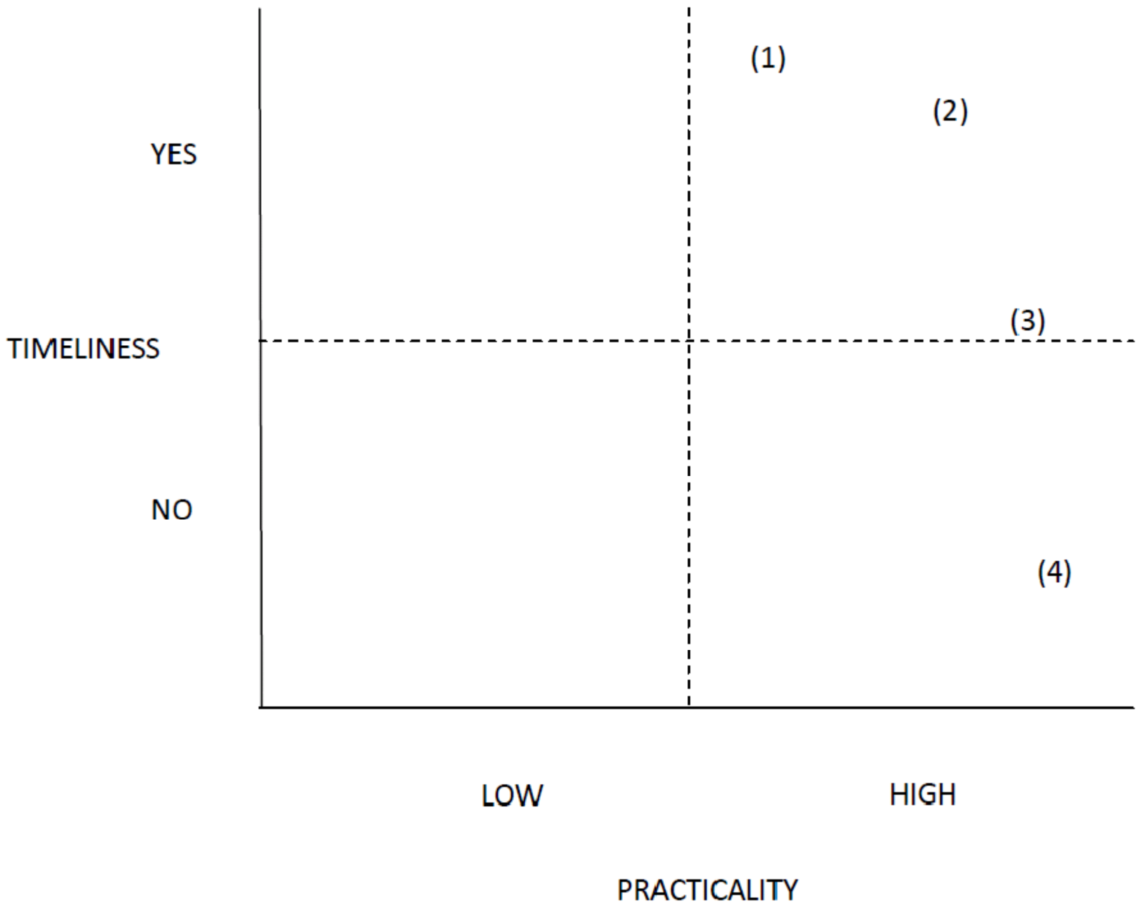
Finally, we believe the arguments set out at the end of paragraph 9.51 as regards there having been no such grandfathering in the past with other substantial market / industry / charging changes (which have had a far greater impact on Users than CMP213) are wholly compelling and therefore there should be no grandfathering with respect to the implementation of CMP213.

Conclusion on Implementation of CMP213

In light of the above our approach on implementation, of CMP213, can be summarised in a two dimension matrix covering the two key implementation goals of timeliness (realising the benefits sooner rather than later) and practicality (can it be done).

[14] Noting that those advocates of Optional Grandfathering appear, up to now, to have been amongst the strongest advocates of Users paying cost-reflective charges – it seems to us that they only regard charges as being 'cost-reflective' if they pay nothing towards those costs and others pay what they should have paid.

Implementation Options (1-4) Characteristics (Timeliness v Practicality)



We believe that CMP213 Original (or any WACM) should be implemented at the earliest practical opportunity so that the demonstrable benefits of moving to a more cost-reflective transmission charging regime can be realised and passed on to end consumers. This, in our view, means Option (1) is the best implementation approach, with Option (2) the next best, Option (3) the following best. Option (4) is the least preferred implementation date as it is wholly inappropriate (in our view) as it fails to meet the Authority's Direction requirements as regards implementation in a "*timely manner*"... "*to ensure benefits are realised as quickly as possible"* .

Annex (2) – SSE detailed reasoning on CMP213 Original and WACMs with respect to five key areas.

We have a number of additional comments that we wish to express. We have grouped these under five main headings:-

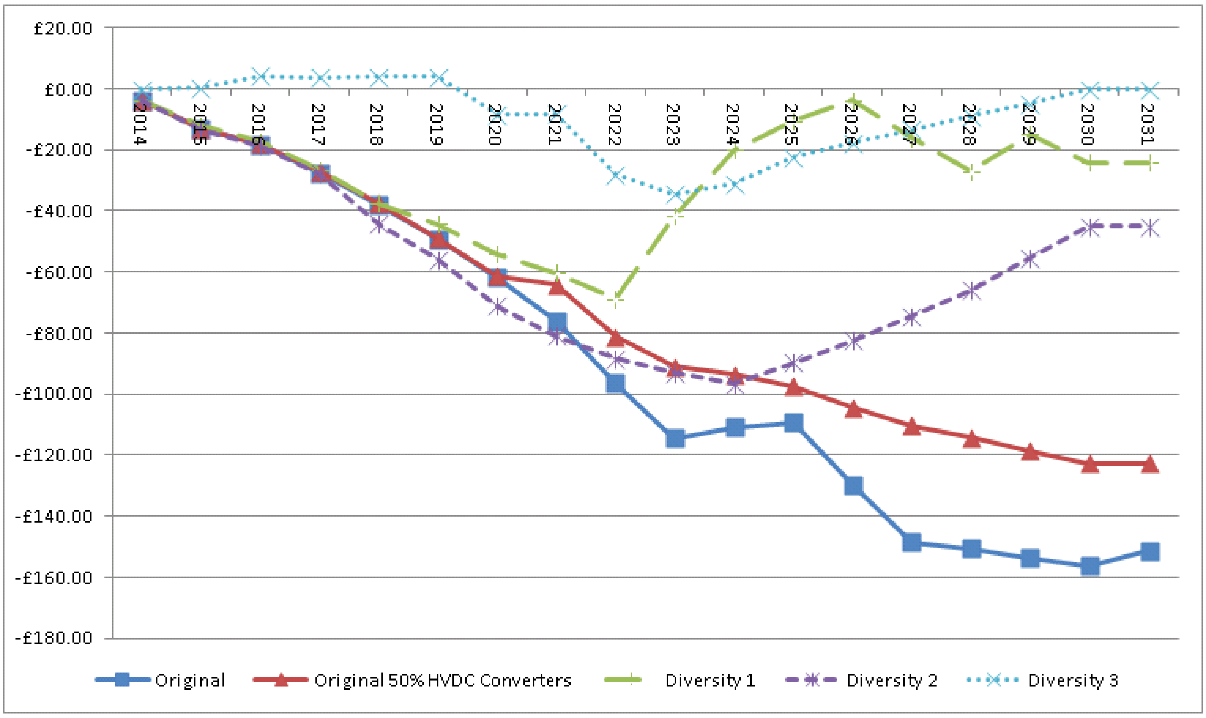
a) Customer Impact;
b) Diversity;
c) HVDC;
d) Islands; and
e) Ofgem Direction / Project Transmit aims

Each of these key areas is explored in more detail below.

a) Customer Impact

In considering the wider impact on end consumers of CMP213 we have been conscious of the need to ensure "that arrangements are in place that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers" (the TransmiT objectives).

Over the period modelled by National Grid, the Original would provide consumers with a total saving of £151.49 whilst for the Original with 50% HVDC Convertors the total saving is £122.71 over the same period. In contrast the three Diversity options provide substantially less value for money benefits, to future consumers, with saving of just £24.03 (Diversity 1), £44.94 (Diversity 2) and £0.11 (Diversity 3). We have represented this in terms of the cumulative effect, compared with the status quo, and this is shown in the graph below.



There are, as would be expected, many variable elements[15] which can impact on the final charges paid by existing and future end consumers. It can therefore be difficult, in isolation, to assessment the impact, of CMP213, on end consumers. That having been said, we commend the effort undertaken by National Grid, as part of the CMP213 assessment process, to model the impact of CMP213 in terms of the Original, the Original with HVDC, and Diversity 1-3. The impact assessment modelling reported in Annex 15 (Volume 2) has

[15] Including such items as wholesale market prices (with the variable nature of global fuel prices and carbon), support regimes (such as the existing arrangements for renewables and, in the future, potentially capacity mechanisms and CfDs) and network charges (with, for example, the introduction of a new price control regime – RIIO – and increasing numbers of OFTOs altering the transmission reinforcements and sub-sea links) as well as other externalities (such as the introduction of the European Network Codes and the European Target Model as well as wider Governmental targets and obligations associated with, for example, emissions and renewables).

provided a very useful analysis of the impact in terms of the value for money to existing and future consumers of CMP213. We continue to study this and we look forward to seeing the additional refined industry impact assessment that National Grid will be providing, in its response to the Code Administrator consultation, as a result of the anomaly in the modelled highlighted by the CUSC Panel (paragraph 7.18, Volume 1).

None the less, we take comfort from (and have sympathy with) National Grid's belief (paragraph 7.18, Volume 1) that the broad outcome and trends associated with the modelling are robust and the results are believed to have an acceptable level of accuracy considering the broader assumptions (noting that modelling uncertainty will always increase over longer time horizons). We agree with National Grid's view that the models are intended to illustrate the longer term broader industry impact of CMP213 (Original and WACMs) and, therefore, would not change the proposals themselves.

We note that renewable generation targets for 2020 and 2030 emissions targets were all met (due to the nature of the Stage 2 modelling) and that transmission investment was similar for all six model results (paragraph 7.15, Volume 1) with the impact of these needing to be assessed through consideration of its impact on (future) consumer bills. In this regard figure A15.25 (on page 243 of Volume 2) is a useful overview of the overall impact / effect of CMP213 (with further detail, in terms of demand tariffs, provided on pages 257-265, Volume 2). This shows that that both the Original and Original with 50% HVDC Convertors has the most beneficial value for money effect, over the period modelled (2013-2030) of options modelled, when compared with the status quo ('baseline') on future consumer bills.

Conclusion on Customer Impact

We are mindful of the Project Transmit objectives, namely:-

> *"....ensuring that arrangements are in place that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers".*

It is clear to us, given that the renewable and emission targets are met with all the options modelled (and thus *arrangements are in place that facilitate the timely move to a low carbon energy sector*) that only two of the options (Original and Original with 50% HVDC Convertors) show the greatest *value for money to existing and future consumers* and are the most beneficial of the CMP213 implementation options (the Original and any of the WACMs) and of these, the Original is 'best' in terms of *value for money to existing and future consumer.*

b) Diversity

The three Diversity options (and indeed the Status Quo and the Original) have been assessed below against the Components of Constraint Costs described in figure 6, page 32, Volume 1 of the Code Administrator consultation document. Given the linkage between constraint costs, the evaluation of required transmission network investments and subsequent charges for use of the system, any efficient, effective and cost-reflective charging methodology should take account of these characteristics, namely:

- Output (taken into account through the ALF)
- Bid prices
- Non-concurrent running
- Constraint coincidence

<u>Generator Output</u>

Diversity 1 and Diversity 2 methods do not adequately take account of the effect of each power station's output, as they understate the proportion of MWkm to which the ALF would be applied. Worse still is that Diversity 3 takes no account of each power station's output via an ALF at all, so from this point of view the methodology will have a discriminatory impact against lower load factor power stations and could not be considered cost-reflective.

The Bath report (Year-round System Congestion Costs – Key Drivers and Key Driving Conditions, 2013) commissioned by RWE and Centrica recommends that "Targeting TNUoS charges and credits in periods and locations where generator output contributes to, or relieves congestion would be an improvement to the existing ICRP methodology." It is clear that a move from charging on peak (Staus Quo) to a system that takes some account of non-concurrent running and constraint coincidence (Original) is a positive move in this direction.

However, the Bath report concludes that "the relationship between load factor and congestion cost most certainly can not be assumed to be linear", but it is clear that the Status Quo position of a linear relationship between capacity and congestion costs is a greater false assumption. The conclusion the Bath report reaches on the basis of this that "Creating a dual background would be a retrograde step in the reflection of costs" is not based on sound logic or analysis.

The Bath report is based on a data sample that does not reflect the future being based upon a period where renewable support, connect and manage, and delays in progressing transmission investment have created a situation which leads to a high level of constraint cost on the B6 boundary. The Bath report conclusions based on this simple assessment of GB constraint costs over this period are not sound.

Bid prices

A fundamental flaw of all Diversity methods is the categorisation of plant into carbon and low carbon. The arbitrary nature of the classification of hydro illustrates a fundamental flaw with these Diversity methodologies in that the level of sharing is assumed to be based on a simple but incorrect linkage of carbon/low carbon status and impact of technology on constraint costs. This is clear from consideration of hydro generation since all the proposed diversity models classify hydro generation as 'low carbon' implying that hydro has a negative variable cost and thus will submit large negative bid prices, both of these are demonstrably incorrect.

The evidence demonstrates that hydro generation should have been included, with CCGT and coal generation, within the 'carbon' (rather than the 'low carbon') classification for Diversity purposes. To treat hydro generation differently from these other dispatchable plant is flawed, not cost-reflective and is likely to result in a TNUoS cost outcome which imposes higher costs on hydro generation than would be justified given hydro generation's contribution to constraint costs.

This is clearly demonstrated by the analysis summarised in Figure 17 (Volume 1). This shows that, based on bid prices and overall volume taken, hydro generation accepted bids accounted for similar or lower costs to the system compared to 'carbon' generation such as coal gas or OCGTs. The consultation has not presented any evidence that the bid prices submitted by hydro generation could be expected to be any more negative than CCGT or coal generation.

It is clear that hydro generation is dispatchable and responds to market price signals in a similar way to CCGT, oil and coal (which are classified, for Diversity purposes, as 'carbon'). Diversity 1 & 2 (as well as the Original) suggest including hydro in the (CMP213) Peak Security tariff background (and charge it accordingly), however, Diversity 1&2 then consider hydro as behaving similary to other "low carbon" plant in terms of constraint cost causation when establishing year round sharing. This is flawed and not cost-reflective.

Analysis of the Elexon generation data from 2012 shows GB hydro generation responding to market power price signals demonstrating an average load factor of 67% during Winter peak hours and only 16% during Summer overnight periods. Therefore, again, hydro generation should have been included along with CCGT, oil and coal within the 'carbon' classification.

The artificial 'construct' of the three Diversity methods of classing generation into 'low carbon' and carbon' is a distortion which is both wholly flawed and demonstrably discriminatory (when plant of either type, in the normal, widely understood, construct of those words can fall into the 'opposite' CMP213 Diversity interpretation of those words e.g. biomass, pumped storage and interconnectors are all classed as carbon.

Finally, the treatment of low carbon generation resulting from all three Diversity methods is likely to end in higher TNUoS costs than is justifiable for renewable generation. This runs counter to the Project Transmit objective in respect of facilitating the timely move to a low carbon energy sector.

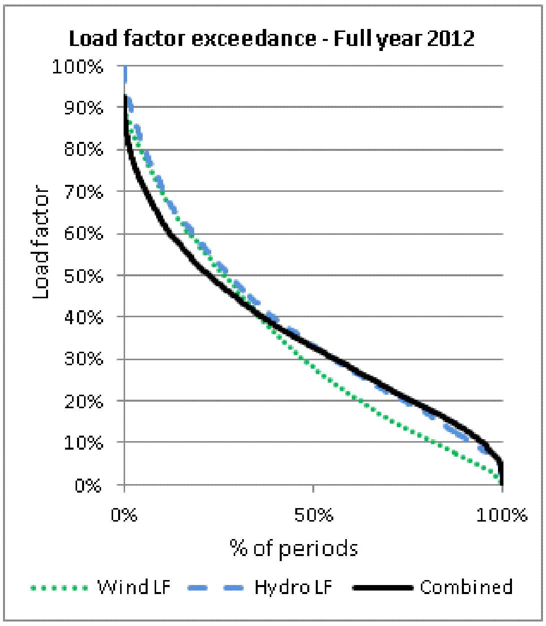
Non-concurrent running

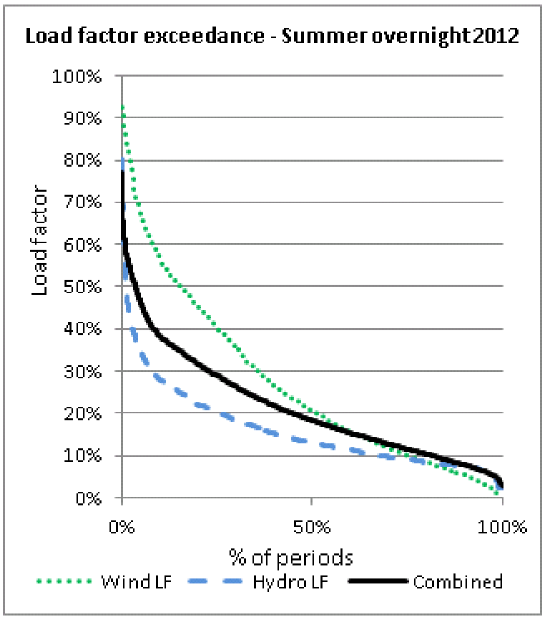
The three Diversity methods overstate the cost of constraints in a transmission charging zone with a high proportion of renewable generation, because they do not attempt to take any account of non-concurrent running of renewable generation i.e. they ignore the fact that hydro and wind will tend to not run at high output at the same time as each other.

This is explored further in paragraph 4.52 (page 27, Volume 2) which proposes that non-concurrent running occurs between thermal and low carbon generation because thermal plant is correlated with demand, but low carbon generation is intermittent. However, the three Diversity options do not take any account of non-concurrent running between renewable technologies (such as those with storage, like hydro), or between power stations of the same generation technology. It is demonstrably the case that, for example, hydro and wind generation (even within the same zone) will run at different times as their 'input fuel' (rain / snow melt and wind) occur a differing times and 'deposit' differing quantities of 'input fuel' depending on weather patterns.

The graph illustrating sharing with Diversity 1 (Figure 18 on p43 of the consultation) and Diversity 2 (Figure 19 on p45 of the consultation) both show that that maximum sharing of incremental transmission cost can only occur when the low carbon capacity in a zone is 50% (and less for Diversity 1) of the total capacity within a zone the amount of sharing of incremental cost falls to 0% when the zone has 100% low carbon capacity. However, this approach is not cost-reflective of (i) the transmission system design, plan or build or (ii) how the transmission system is used by that generation. This is because even at 100% low carbon within a transmission charging zone, there will still be substantial sharing, both between different low carbon technologies (especially wind and hydro) and even between power stations of the same generation technology. There is also sharing between generation and demand side response that has not been taken account of (see our comments below on demand side response).

In particular, for the running of wind and hydro, wind and hydro generation both only achieve high load factors for a relatively small percentage of the year. If the generation of both is considered together, then the number of settlement periods when both are performing at a high load factor, at the same time, is particularly low. Elexon 2012 data shows the average monthly correlation between transmission connected hydro and wind generation was very low at only 0.1. The graphs below uses this data to illustrate the load factor exceedance curves for transmission connected wind and hydro generation, along with an equal weighted combined load factor. This demonstrates that concurrent running between hydro and wind is particularly low during Summer overnight periods when local constraints due to wind would be most likely.





This low correlation is also a function of the effect described above that hydro generation is dispatchable and will tend to generate less during periods of lower wholesale market prices. As the level of wind penetration increases, wind volumes will increasingly drive wholesale market prices, which will result in even lower concurrent running of wind and hydro generation as hydro will be dispatched to avoid the low wholesale market prices periods resulting from higher volumes of wind generation output.

TNUoS charging zones cover a large geographical area. Wind farms will tend to be distributed relatively widely across each of these zones and will be less than 100% correlated, as wind speed (and direction) alters as high / low pressure weather systems traverse across the zone from hour to hour, day to day, week to week and season to season.

This is supported by the work currently being undertaken by National Grid and industry participants on the characteristic of wind generation in the BM. Our assessment is that just as wind generation increases (and decreases) as wind speed increases (or decrease) so too does it's output decline (as the wind speed increases) in a known way, as wind turbines 'apply the brake' at high wind speeds. Taken together this will mean even in a transmission charging zone with 100% wind generation, power stations will, intrinsically, still share the transmission network to some degree.

Other generation technologies classed (artificially) as 'low carbon' by the three Diversity methods (i.e. wind, hydro, wave and tidal) will also share between technologies and between power stations.

<u>Constraint coincidence</u>

All three Diversity methods disregard the impact of system constraint coincidence and so they understate sharing. This is flawed and is discriminates against power stations with a lower constraint coincidence such as intermittent renewable and hydro.

The three Diversity methods do not define or address the correlation with constraints and they do not attempt to define what these constraint periods are likely to be. The drivers of correlation with system constraint are different for different generation technologies:

- Wind – In a transmission charging zone with a high share of wind generation, system constraints would be most likely during periods of relatively high wind volume combined with relatively low demand, such as overnight in the summer. These periods will also be correlated with low wholesale market prices which dispatchable plant (such as hydro) would be dispatched to avoid.

- Hydro – Dispatchable hydro will tend to be dispatched to avoid generating during periods of low wholesale market prices, so will tend to be counter correlated with periods of system constraint caused by high wind such as windy overnights in the summer

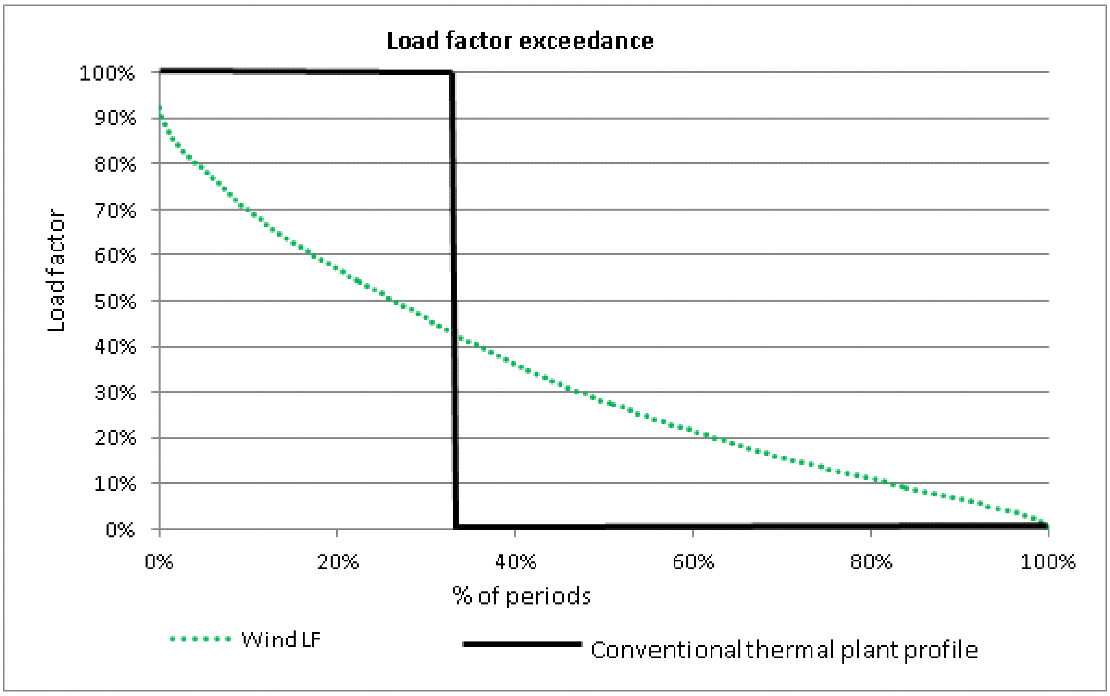
- Other intermittent renewables – Intermittent renewables such as run-of-river hydro, wave and tidal will tend to have a very low correlation of output with wind generation, so will tend to exhibit a relatively low correlation between peak generation and periods of constraint in a high wind transmission charging zone.

All three of the Diversity methods fail to take account of the fact that wind generation tends to operate at high levels of output for a much smaller percentage of the year than a thermal station of an equivalent load factor. Wind farms may exhibit lower bid prices than a conventional thermal station, but an appropriate cost benefit analysis would demonstrate that since this is applied to a relatively small number of settlement periods, the optimum connection for a wind-only generator is less than 100% of its (MW) capacity.

The graph below illustrates this using Elexon wind data for 2012 compared with an illustrative conventional dispatchable power station with an equivalent annual load factor of circa 34%.

It should be noted that this effect would be much more powerful when looking at onshore wind farms in a single transmission charging zone, such as those in the North of Scotland because the Elexon data includes the total GB portfolio which includes offshore wind farms which will tend to operate at higher load factors for a higher proportion of the time (compared to onshore wind farms).

It should also be noted that this effect would be much more powerful since wind will only tend to be correlated with constraints during periods of relatively low demand, such as overnight in the summer, so many of the periods of high wind generator load factor which occur during the daytime would tend to not be correlated with system constraints because the higher wind volume will tend to be absorbed by higher demand on the transmission system.



Demand Sharing

We consider that a fifth element be added to the characteristics being reviewed when sharing within a zone is assessed, that of demand sharing. All three Diversity approaches assume that sharing, within and between transmission zones, is only between generators and is based on bid prices etc. However, recent developments bring this central tenet of the three Diversity approaches into doubt. In particular, the publication of a number of European Network Codes, including the Balancing Code (published 24th April 2013), together with Ofgem's recent consultation on demand side response[16] forecast significant market change, with respect to demand side response, over the medium term (between now and 2020, when smarter meters are expected to be 'universal' across all GB consumers) and beyond.

All three CMP213 Diversity approaches ignore the substantial role that supply (in the form of demand side response) is expected to play, and can contribute, in terms of managing constraints etc., and transmission system planning / building and operation. Given the growth in demand side response that Ofgem (and others) foresee, it would be incorrect to assume that the NETSO, when determining what to constrain off within a transmission charging zone, would only have the choice between, say, generator X and generator Y (be they 'low carbon' or 'carbon') when, in fact, they will have consumer(s) Z (be that individually or via their supplier(s) or aggregator(s)). In this credible situation who is to say that consumer(s) Z is 'low carbon' or 'carbon', let alone how their bid price will be reflected, in terms of CMP213 Diversity.

Status Quo and Original

Finally, in relation to the Status Quo and the Original. It is clear that the current 'status quo' (baseline CUSC) does not take account of any of the factors (output, bid prices, non-

[16] "Creating the right environment for demand side response" (Reference 64/13 30th April 2013)

concurrent running or constraint coincidence) as it is based simply on an assessment of the network at peak and therefore it is appropriate that a modification (to the charging methodology) is undertaken to account t for these factors in the methodology.

In terms of the_CMP213 Original, it is more cost-reflective than the 'status quo' because it takes account of a power station's output, which is the most significant influence on constraint costs. This is done via the use of an annual load factor (ALF) applied to the Year Round generator TNUoS tariff. This approach implicitly takes account of the interaction between the effects of generator bid prices, non-concurrent running and constraint coincidence and assumes that all Year Round transmission circuits are shared. Whilst this assumption is a simplification, it is the most representative of genuine transmission system costs. It provides, in our view, the best balance of cost reflectivity and simplicity together with ease of understanding and application without creating undue discrimination or introducing complexity and confusion (particularly for smaller parties).

Conclusion on Diversity

In summary , the CMP213 Original proposal provides, in our view, a very good balance between being relatively simple and easy to understand whilst being appropriately cost-reflective and not unduly discriminatory or confusing (particularly for smaller parties).

In stark contrast the three Diversity methods deliver the worst combination of simplicity and cost-reflectivity, since they are more complicated and difficult to understand or forecast / plan operations to (particularly for smaller parties) than the CMP213 Original and also will be less cost-reflective (of the transmission system designed / built or operated, day-to-day) and result in discrimination against low load factor plant. In an attempt to take account of Diversity, the three Diversity methods have made simplifying assumptions which grossly understate generation sharing in transmission charging zones with a high proportion of low carbon generation and take no account, for example, of bid prices from demand side response in that zone.

Diversity 2 is even less cost-reflective than Diversity 1, because it assumes a maximum of only 50% shared incremental cost, instead of the maximum of 100% assumed by both the Original and Diversity 1.

Of all three Diversity methodologies, the Diversity 3 method is the least cost-reflective, in terms of transmission system design, plan or build or how the transmission system is used by that generation, and most discriminatory of the three diversity methods. It is also, for the avoidance of doubt, less cost-reflective, and more discriminatory, than the CMP213 original.

An argument put forward in favour of Diversity 3 by its proposer was that compared with the Original, it would provide a relatively greater incentive to build high load factor generation plant in a transmission charging zone with mainly low carbon plant. However this (TNUoS) price signal would be a perverse incentive and less cost-reflective than the incentive provided by the CMP213 Original.

It would be the wrong price signal to encourage high load factor generation plant into such a transmission zone because it would create additional constraint costs during periods outside peak demand. This is because the high load factor generation plant would tend to operate during periods of relatively high output from the (intermittent) low carbon generation in that zone. By comparison, the CMP213 Original already provides the correct incentive to build dispatchable generation plant in a transmission charging zone with a high penetration of intermittent generation via the Peak Security tariff. The price incentive provided by the CMP213 Original is correct because it favours dispatchable generation plant with a relatively low load factor, which is able to serve peak demand, but which does not place undue strain on the transmission network outside of peak demand periods.

c) HVDC

Summary

In coming to a view on the matter of the treatment of HVDC we have considered carefully the summary of the CMP213 Workgroup discussions set out in Section 5 (Volume 1) along with the associated information in the Annexes (Volume 2). In our view it is appropriate to update the existing 'status quo' CUSC charging methodology to reflect the planned introduction of HVDC technology into the GB transmission system. Given this there is then a question of how that should be achieved. We note that the CMP213 Original would treat power flows on HVDC transmission circuits as if they were AC circuits. However, having done so there is then the matter of the associated expansion factor for such a link.

Having considered the various options and differing approaches associated with the treatment of HVDC transmission circuits we have concluded that the evidence is overwhelming that elements of the HVDC convertor stations are equivalent to AC elements of the transmission system (which are, under the current CUSC charging methodology, charged 'socially' rather than 'locationally').

These reasons also apply to the 'QB' type benefits that HVDC links provide to the operation of the system and, therefore, this QB benefit should be treated in a similar manner, as the AC equivalent, for HVDC links.

It therefore follows that it would not be either cost-reflective or better for competition (in generation) if the TNUoS charges, for those (AC) equivalent elements of HVDC links, were not also charged, socially (rather than, as proposed, fully locationally).

We concur with the CMP213 Workgroup position, as set out in paragraph 5.55 (Volume 1), namely that a number of attributes would better facilitate the applicable CUSC (charging) objectives. These attributes include:-

i) Remove 50% of the (HVDC) converter station costs based on elements similar to AC substations;

ii) Remove 60% of the (HVDC) converter station costs based on elements similar to AC substations and controllability similar to QBs; and

iii) Remove a specific percentage of the (HVDC) converter station costs based on elements similar to AC substations.

We support, in principle, all the WACMs with these elements. However, these benefits (in terms of better cost reflectivity, facilitating competition and reflecting changes in the transmission business) do not outweigh the far larger dis-benefits associated with Diversity methods 1-3 (and, therefore, we do not support any WACMs with Diversity 1-3, even if they include these HVDC 'options').

In our view option (ii) ('remove 60%') is the most preferred, followed by option (i) ('remove 50%') and then option (iii) ('remove *x*%') as the evidence set out in the consultation documentation clearly supports this.

Introduction

In examining the solutions to the defect that have been explored by the CMP213 Workgroup two options that were not taken forward for consultation provide a relevant background to assess the alternatives against and we have provided our views on these first, namely (a) Treat HVDC cost as onshore AC transmission technology cost when calculating the expansion factor and (b) Remove all converter station costs from the calculation. Neither of these have been taken forward. Nevertheless we have taken the opportunity to record below the reasons why we continue to support these approaches.

a) Treat HVDC cost as onshore AC transmission technology cost when calculating the expansion factor

We note the analysis undertaken to explore how to treat HVDC costs in terms of (onshore) AC transmission technology costs as set out on pages 65-67 (Volume 1) and Annex 14.8 (pg 219-227, Volume 2).

We are mindful of the public statements from Ofgem, DECC and the two TOs involved in building the Western HVDC ('Bootstrap') link indicating that the cost of the offshore v onshore options (for this link) are either similar (the two TOs) or less (Ofgem and DECC). Given that cost similarities it therefore follows that the charges (to the Users of that link, via their TNUoS tariffs) should also be similar if the capacity of the offshore and the onshore links are similar. As the capacity of the Western HVDC link is known (~2.2GW) it should therefore be a simple process to calculate what the fully cost-reflective charge should be in treating the (offshore) HVDC link on none discriminatory terms to the (onshore) AC link. In this respect Table 19 (page 66, Volume 1) clearly demonstrates what the equivalent cost-reflective expansion factor should be for the HVDC link based on various capacity figures for the equivalent (onshore) AC link.

In our view this is how the expansion factor, for the Western HVDC ('Bootstrap') link, should be treated. That having been said, we recognise that this option was not taken forward, either as part of the CMP213 Original or via a WACM.

b) Remove all converter station costs from the calculation

We agree with those CMP213 Workgroup members (and respondents to the Workgroup consultation) that support the removal of 100% of the HVDC converter station costs from the expansion factor calculation. In our view this would be consistent with the treatment of other fixed cost or non-distance related cost elements of the onshore transmission system AC substations, which are not locationally charged in TNUoS. We agree with the arguments (in paragraph 5.14, Volume 1) that HVDC converter stations would have broadly the same function as transformers in that they effectively link different elements of the transmission system and, furthermore, that HVDC converter stations can also provide system services (including reactive compensation and post-fault power flow redirection), which can be considered analogous to the benefits provided currently by transmission assets such as Quadrature-Boosters (QBs).

These arguments together with the additional arguments set out in paragraph 5.15 (Volume 1) and Annex 14.3 (Volume 2) establish, in our view, a strong case for why all convertor station costs should be removed from the calculation of the expansion factor for HVDC transmission circuits. That having been said, we recognise that this option was not taken forward, either as part of the CMP213 Original or via a WACM.

Given that neither (a) treating HVDC cost as onshore AC transmission technology cost when calculating the expansion factor or (b) removing all converter station costs from the calculation has gone forward, we give our views below on the other aspects of HVDC that are part of CMP213 (the Original and / or WACMs).

<u>Expansion Factor</u>

We note the CMP213 Workgroup deliberations, with respect to the expansion factor for HVDC transmission circuits, as set out in the consultation document. The Workgroup looked, in particular, at three aspects and we provide our views below on the ones that form part of CMP213 (the Original and / or WACMs).

Remove some converter station costs from the calculation

Notwithstanding our comments above (about removing all convertor station costs) we agree with those CMP213 Workgroup members (and Workgroup consultation respondents) who argue that a certain percentage of the convertor station costs should be removed from the calculation of the expansion factor for HVDC transmission circuits. What this certain percentage should be was explored by the CMP213 Workgroup and we concur with the group that there are, broadly speaking, two possible approaches; either a 'generic' or 'specific' figure.

<u>Generic</u>

In terms of the 'generic' approach we find the detailed analysis undertaken by the Workgroup to be compelling. As noted in paragraph 5.24 (Volume 1) it is a "fact that a proportion of HVDC converter station costs can be related to AC substation equipment" – the question is what proportion (percentage) that is. The independent analysis reported in the Cigre paper 186 (and summarised in Table 7, pg 98, Volume 2) clearly demonstrates that approximately half of the HVDC convertor station costs (in terms of the main elements that go into the equipment and its construction) are equivalent to the AC equipment that would be used as an alternative to HVDC.

In our view the case has demonstrably been made for removing a generic proportion of the HVDC convertor station costs from the expansion factor calculation and that based on the independent research this should be 50% which, with HVDC convertor stations accounting for approximately half the overall cost of an HVDC link, means that the HVDC link expansion factor should be reduced by 25%.

<u>QBs</u>

We agree with those CMP213 Workgroup members (and Workgroup consultation respondents) that a case has been made for also reflecting (within the expansion factor calculation) the role that QBs provide in terms of transmission system operation and stability. The arguments in paragraph 5.30 (Vloume 1) and Volume 2 (pg99-100) are very persuasive in this regard.

In our view QBs should not be charged locationally be they located on the AC or HVDC part of the transmission system. The removal from the expansion factor calculation is both cost-reflective of the service they provide and equitable in terms of treatment (as both AC and HVDC QBs would be treated identically) and thus non discriminatory.

<u>Specific</u>

We note that there is a *variation* on the 'generic' approach which is to base the actual percentage figure on the 'specific' costs of each HVDC link. Clearly if the actual data could be obtained for each HVDC link then, on the ground of better cost reflectivity, it would (in principle) be better to have a 'specific' rather than a 'generic' approach. However, we agree with those CMP213 Workgroup members who believe that obtaining such information may be very difficult (if not impossible) given the 'turn-key' nature of such contracts and, potentially, commercial confidentiality consideration on the part of the manufacturer and possibly the purchaser (the TO). In addition using a 'specific' approach would introduce an element of uncertainty for power station projects whose TNUoS charges are linked to HVDC transmission circuit(s) as they would not be certain until, presumably, the TO had completed the project and reported (to the TSO) the actual cost data (in order for the 'specific' figure for that HVDC link to be calculated, and then charged to the affected generator(s)). This uncertainty, on the part of generators, could be said to not better facilitate competition in generation.

In our view it is a fine line between using a 'generic' or using a 'specific' approach. We note that in the absence of the data necessary to calculate the 'specific' figure for each HVDC project that the default would be to use the 'generic' figure. This is a sensible and pragmatic approach we which support.

Given that both the 'generic' and the 'specific' approaches both better reflect the actual situation; i.e. that certain elements of a HVDC convertor station costs are equivalent to AC elements, which are charged non locationally, it is our view that both the 'generic' and the specific' approaches (including the QBs) are a substantial improvement on both the baseline 'status quo' and, indeed, the CMP213 Original.

Not withstanding this, as we have noted in Annex (3) below, these beneficial attributes are not enough to overcome the hugely detrimental effect that the 'sharing' attributes would (if implemented) introduce.

Other options

In addition to the matter of the expansion factor for HVDC transmission circuits, the CMP213 Workgroup also considered three related items. We provide our views on each of these below.

> *i. Review the overhead factor (i.e. 1.8%) used when annuitising the capital cost in the calculation of the HVDC expansion constant*

We note the detailed analysis of this item, by the CMP213 Workgroup (Volume 2 pg101-103), and we agree with the Workgroup that the benefits of charging simplicity and stability arising from the use of a single overhead factor for all transmission assets (HVDC and none HVDC) outweigh any minor increase in (charging) cost reflectivity that may arise, when compared with a more specific treatment (if one were to be established).

> *ii. Calculate the 'desired flow', and hence notional impedance, by balancing flows across the single most constrained transmission boundary rather than all the transmission boundaries the HVDC link 'crosses'*

We note the analysis of this item, by the CMP213 Workgroup (Volume 2 pg103), and we concur with the majority of the Workgroup (and the Proposer) the use of a 'multiple boundary' approach (rather than a 'single boundary') is appropriate and should, therefore, be reflected in the CUSC charging methodology.

> *iii. Review security factor calculation in light of long (MWkm) HVDC links comprised of single transmission circuits that parallel the AC transmission network*

We note the analysis of this item, by the CMP213 Workgroup (Volume 2 pg104), and we agree with those Workgroup members that where a single transmission circuit has been built (rather than two) that a single security factor (1.0) should be used (rather than 1.8 where two circuits are built).

d) Islands

We note the detailed deliberations of the CMP213 Workgroup (along with the helpful comments provided by respondents to the Workgroup consultation) in respect of a number of attributes associated with Island transmission circuits associated.

These deliberations resulted in a number of amendments (to CMP213 Original) being taken on board by the Proposer and, as a result, the number of items that required further options to be explored were similar to HVDC, namely

> *i) Remove all converter station costs from the calculation;*
> *ii) Remove some converter station costs from the calculation; and*
> *iii) Treat HVDC cost as onshore AC transmission technology cost when calculating the expansion factor.*

We have provided elsewhere in this Annex (3) (under 'HVDC' above) our detailed reasons as to why we support (i) the removal of all HVDC convertor station costs from the expansion factor; and (ii) the removal of some HVDC convertor station costs. For the sake of brevity we avoid repeating our views here – however, for the avoidance of doubt, those reasons (associated with HVDC) are also applicable here (for islands).

In terms of the matter of the voltage source convertors (VSCs) which are explored in the consultation document (pg75-76, Volume 1) and Annexes 14.4 and 14.6 (Volume 2) we agree, for similar reasons to those we outlined in this Annex (2) (under 'HVDC' above) as regards the benefits associated with QBs that the VSCs are also beneficial in terms of transmission system operation and, therefore, the costs of VSCs should be removed in a similar manner as QBs; i.e. 20% for VSCs / 10% for QBs.

e) Ofgem Direction / Project Transmit aims

In coming to a view on CMP213 (Original and the WACMs) we have taken into account other matters indentified in the consultation documentation, the Ofgem Direction and the Project Transmit aims. We explore these further below.

Summary

We conclude that a number of the WACMs have component elements which are not only *worse* (in terms of the applicable CUSC objectives) but also run counter to the aims of the Project Transmit and / or the Authority's Direction and would, in our view, be a gross distortion of the process (and call into question the viability of the 'SCR' process) if a WACM were to be implemented which so demonstrably ran counter to the Direction.

Specifically, the WACMs including sharing in terms of Diversity 1 to 3 are not consistent with the GB SQSS approach to transmission investment planning undertaken by the TO(s) when actually building new (or expanding / enhancing) transmission circuits, and its clear that Diversity 3, with its single background, runs directly counter to the dual background approach set out in Project Transmit and the Direction.

Finally, with respect to Diversity 3, it would, in our view, be a total travesty of the SCR process If after some three years of detailed investigation, we ended up, to all intent and purpose, back where we started with a TEC based (100% ALF) approach to TNUoS charging for GB generators.

<u>The Ofgem Direction and the Project Transmit aims</u>

Whilst not a specific Applicable CUSC (charging) Objective we would like to note that a number of the WACMs have component elements which are not only *worse* (in terms of the applicable objectives) but also run counter to the aims of the Project Transmit and / or the Authority's Direction (to National Grid) which resulted in CMP213 being raised, in particular:-

> *"…. the Authority considers that it is appropriate for industry to consider further developing the method of calculating TNUoS charges within the UoS charging methodology in accordance with the principles of investment cost related pricing (ICRP) so that:*
>
> *a) it better reflects the differing incremental impacts of individual generators on the Transmission Owners• costs in a manner which is consistent with the Security and Quality of Supply Standard (SQSS),*
>
> *b) it maximises benefits to current and future consumers, and*
>
> *c) it more generally achieves the TransmiT objectives[17]."*

[17] "Project TransmiT.... an independent and open review of electricity transmission charging and associated connection arrangements with a view to ensuring that arrangements are in place that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers (the TransmiT objectives)." [page 1 of the Authority Direction]

In light of these objectives, we believe that several of the WACMs can be discounted by virtue of being wholly incompatible with the Direction.

The WACMs including sharing in terms of Diversity 1 to 3 are not consistent with the GB SQSS approach to transmission investment planning undertaken by the TO(s) when actually building new (or expanding / enhancing) transmission circuits. This is reinforced by the results of the Impact Assessment Modelling Results published as Annex 15 (Volume 2) to the consultation document. This clearly shows that options that include Diversity 1 to 3 sharing methodologies result in higher future consumer bills than the CMP213 Original (or Original with 50% HVDC) modelled.

Furthermore, it is demonstrably clear that Diversity 3, with its single background, runs directly counter to the dual background approach which was explored in great detail in the Project Transmit process and which resulted in a dual background approach being clearly set out in the Direction in the following way:-

> *"the Authority considers .... that proposals should be developed for modifying the UoS charging methodology for generation charges so as better to reflect the "year round" and "peak" backgrounds applied in the SQSS ......*
> *in developing such modifications, that consideration should be given to whether it is appropriate to assume that intermittent generation technology types should only contribute to charges based on the "year round" background, and ......*
> *that consideration should be given to how provisions reflecting the year round background might best be structured and levied so as more accurately to reflect the incremental costs of transmission infrastructure investment on the efficient year round operation of the transmission system in accordance with the SQSS."*

The Direction went on to note that:-

> *".... generator charges are calculated by reference to the impact of different types of generation located at different points in the network:*
>
> *i) on the incremental costs of transmission infrastructure investment required to secure demand at system peak (the peak condition), and*
>
> *ii) on the incremental costs of transmission infrastructure investment associated with efficient year round operation of the transmission system (the year round condition) in a manner consistent with the SQSS"*

If a WACM which incorporated Diversity 3 were, therefore, to be implemented it would, in our view, fatally undermine the whole SCR *raison d'etre* as after some three years of detailed investigation (circa 18 months by the Authority assisted by numerous independent academic inputs, industry stakeholder engagement and consultation, then circa 12 months by industry, via the CUSC process, followed by circa 4 months by the Authority), we ended up, to all intent and purpose, back where we started with a TEC based (100% ALF) approach to TNUoS charging for GB generators.

Annex (3) – SSE detailed reasoning on the Main component Elements of CMP213 Original with respect to the Applicable CUSC (charging) Objectives.

This Annex (3) sets out firstly the main component elements of CMP213, secondly the UoS charging methodology applicable objectives (both for ease of reference), then sets out our reasoning behind our views as to whether the different elements are i) Better than the Baseline (Vote One) and ii) Better than the Original (Vote Two).

Main Component Elements of CMP213
Extent of Sharing
No Diversity
Diversity Method 1
Diversity Method 2
Diversity Method 3
Form of Sharing
YR - ALF historic specific (5 years)
YR - Hybrid
Parallel HVDC
Specific EF 100% Conv+100%Cable (original)
Specific EF; generic 40% Conv+100%Cable (AC sub + QB)
Specific EF; generic 50% Conv+100%Cable (AC sub)
Specific EF; specific *x*% Conv. cost reduction (AC sub)
Islands
Specific EF 100% Conv+100%Cable (original)
Specific EF; generic 30% Conv+100%Cable (AC sub + STATCOM)
Specific EF; generic 50% Conv+100%Cable (AC sub)
Specific EF; specific *x*% specific Conv. cost reduction (AC sub)

Use of System Charging Methodology – Applicable Objectives

(a) that compliance with the use of system charging methodology facilitates **effective competition in the generation and supply of electricity** and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

(b) that compliance with the use of system charging methodology results in charges which **reflect, as far as is reasonably practicable, the costs** (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

(c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, **properly takes account of the developments in transmission licensees' transmission businesses**.

VOTE ONE – BETTER THAN BASELINE

Objective	[Extent of sharing] No Diversity
(a)	Yes – By better reflecting the costs of using the transmission system onto those who give rise to those costs, by being based on usage of that network at Peak and Year Round, this component better facilitates effective competition than the Baseline. It therefore better meets Applicable Objective (a) than the Baseline.
(b)	Yes – The attributes of CMP213 Original, with respect to Sharing, which links TNUoS charges to the use of the transmission system at both the Peak and also Year Round better reflects the costs of the transmission system onto Users than the Baseline. It therefore better meets Applicable Objective (b) than the Baseline.
(c)	Yes - The transmission businesses are developed in line with the GB SQSS, which incorporates capacity sharing as a factor in determining the need for transmission capacity investment. We believe that the approach to sharing outlined in the CMP213 Original proposal, i.e. no diversity, best matches the developments in the *transmission licensees' transmission businesses.*
Overall	Yes – for the reasons set out above. For the avoidance of doubt, these benefits associated with No Diversity, in terms of Applicable Objectives (a), (b) and (c), outweigh any dis-benefits (in terms of Applicable Objectives (a), (b), or (c)) arising from either the 'HVDC' or 'Island' components.

Objective	[Extent of sharing] Diversity Method 1
(a)	No – The complexity associated with Method 1 together with other factors including the lack of a solution to charges in Negative Zones and the introduction of undue discrimination into the methodology with respect to the unequal treatment of certain plant as 'low carbon' (and others as 'carbon') mean that Method 1 is detrimental to effective competition in the generation of electricity. Therefore it does NOT better meet Applicable Objective (a) than the Baseline.
(b)	Neutral – Whilst there are some cost-reflective enhancements, compared to the Baseline, with Method 1 there are also some detrimental attributes, in terms of cost reflectivity with Method 1. For example, the lack of a solution to charges in Negative Zones and the introduction of undue discrimination into the methodology with respect to the unequal treatment of certain plant as 'low carbon' (and others as 'carbon'). This means that Method 1 is neutral as regards better reflecting costs.
(c)	No - The transmission businesses are developed in line with the GB SQSS planning approach which does not incorporate "Diversity". We believe that the approach to sharing outlined in the CMP213 Original proposal, i.e. no

	diversity, best matches the developments in the *transmission licensees' transmission businesses.*
Overall	No – for the reasons set out above. For the avoidance of doubt, these dis-benefits associated with Method 1, in terms of Applicable Objectives (a) and (c), outweigh any benefits (in terms of Applicable Objectives (a), (b) and (c)) arising from either the 'Form of Sharing', 'HVDC' or 'Island' components.

Objective	**[Extent of sharing] Diversity Method 2**
(a)	No – The complexity associated with Method 1 is even greater with Method 2 which together with other factors including the introduction of undue discrimination into the methodology with respect to the unequal treatment of certain plant as 'low carbon' (and others as 'carbon') mean that Method 2 is detrimental to effective competition in the generation of electricity. Therefore it does NOT better meet Applicable Objective (a) than the Baseline.
(b)	No – Method 2 has a number of significant detrimental attributes, in terms of cost reflectivity, including the application of an arbitrary '50%' figure as well as the unequal treatment of certain plant as 'low carbon' (and others as 'carbon'). Therefore it does NOT better meet Applicable Objective (a) than the Baseline.
(c)	No - The transmission businesses are developed in line with the GB SQSS planning approach which does not incorporate "Diversity". We believe that the approach to sharing outlined in the CMP213 Original proposal; i.e. no diversity; best match the developments in the *transmission licensees' transmission businesses.*
Overall	No – for the reasons set out above. For the avoidance of doubt, these dis-benefits associated with Method 2, in terms of Applicable Objectives (a) (b) and (c), outweigh any benefits (in terms of Applicable Objectives (a), (b) and (c)) arising from either the 'Form of Sharing', 'HVDC' or 'Island' components.

Objective	**[Extent of sharing] Diversity Method 3**
(a)	No – The complexity associated with Methods 1 and 2 are even greater with Method 3 which together with other factors including the introduction of undue discrimination into the methodology with respect to the unequal treatment of certain plant as 'low carbon' (and others as 'carbon') mean that Method 3 is detrimental to effective competition in the generation of electricity. Therefore it does NOT better meet Applicable Objective (a) than the Baseline.
(b)	No – Method 3 has a number of significant detrimental attributes, in terms of cost reflectivity, including the application of an arbitrary '50%' figure as well as the unequal treatment of certain plant as 'low carbon' (and others as 'carbon'). Therefore it does NOT better meet Applicable Objective (a) than the Baseline.
(c)	No - The transmission businesses are developed in line with the GB SQSS planning approach which does not incorporate "Diversity". We believe that the approach to sharing outlined in the CMP213 Original proposal, i.e. no

	diversity, best matches the developments in the *transmission licensees' transmission businesses.*
Overall	No – for the reasons set out above. For the avoidance of doubt, these dis-benefits associated with Method 3, in terms of Applicable Objectives (a) (b) and (c), outweigh any benefits (in terms of Applicable Objectives (a), (b) and (c)) arising from either the 'Form of Sharing', 'HVDC' or 'Island' components.

Objective	**[Form of Sharing] YR - ALF historic specific (5 years)**
(a)	Yes – The application of a 'usage' element based on the Users' actual ALF (over a set period) into TNUoS charges to reflect Users' usage of the transmission system, not only better reflects costs (see (b) below) but also better facilitates competition in the generation of electricity. Therefore, with respect to the Baseline, this better facilitates Applicable Objective (a).
(b)	Yes – The application of a 'usage' element based on the Users' actual ALF (over a set period) into TNUoS charges to reflect Users usage of the transmission system, compared with the Baseline, '100%' ALF demonstrably better reflects the cost of using the transmission system onto those that give rise to those costs.
(c)	Neutral
Overall	Yes – for the reasons set out above.

Objective	**[Form of Sharing] YR - Hybrid**
(a)	Yes – In addition to the benefits that the introduction of an ALF affords, the Hybrid option (by providing Users with the ability, if they wish, to provide their own forecast ALF) is an enhancement which better facilitates competition in the generation of electricity as it allows Users (if they wish) to better reflect changing market conditions. Therefore, with respect to the Baseline, this better facilitates Applicable Objective (a).
(b)	Yes –The application of a 'usage' element based on the Users' actual ALF (over a set period) into TNUoS charges to reflect Users usage of the transmission system, compared with the Baseline, '100%' ALF demonstrably better reflects the cost of using the transmission system onto those that give rise to those costs. Therefore, with respect to the Baseline, this better facilitates Applicable Objective (b). Having a forecast option is a further, beneficial, enhancement in terms of cost reflectivity. Therefore, with respect to the Baseline, this better facilitates Applicable Objective (b).
(c)	Neutral
Overall	Yes – for the reasons set out above.

Objective	**[HVDC] Specific EF 100% Conv+100%Cable (original)**
(a)	No – As the locational TNUoS charge includes items that should not be recovered locationally (see (b) below) this is harmful to competition in generation. Therefore it does NOT better meet Applicable Objective (a) than the Baseline.
(b)	No – By reflecting the full 100% of the convertor station costs into the

	locational TNUoS charges even though there is clear evidence, as set out in the Workgroup report, that certain cost components of the convertor station are equivalent to onshore AC items which would not be recovered via the locational TNUoS charges this means that this is not better than the Baseline. Therefore it does NOT better meet Applicable Objective (b) than the Baseline.
(c)	No - The case for investment in HVDC e.g. the Western Bootstrap has been made on the basis that the cost of the HVDC link is either similar to, or less than the equivalent (onshore) AC link. It is also based on savings from reduced constraint costs associated with the delays to planning affecting the onshore solution. The result is an expansion factor that is significantly greater that the equivalent OHL. The inclusion of 100% of the HVDC converter station costs makes this situation even worse, less cost-reflective and less reflective of the economic developments of the *transmission licensees' transmission businesses.* Therefore it does NOT better meet Applicable Objective (c) than the Baseline.
Overall	No – for the reasons set out above.

Objective	**[HVDC] Specific EF; generic 40% Conv+100%Cable (AC sub + QB)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Baseline.
(b)	Yes - By reflecting a proportion of both the convertor station costs and the QB costs into the non locational TNUoS charge, based on the clear evidence set out in the Workgroup report that certain cost components (of the convertor station and QBs) are equivalent to onshore AC items, this is better than the Baseline. Therefore it does better meet Applicable Objective (b) than the Baseline.
(c)	Yes – Whilst this approach still does not fully take account of the development of the business of the TO(s), in terms of HVDC transmission circuits, we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[HVDC] Specific EF; generic 50% Conv+100%Cable (AC sub)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Baseline.
(b)	Yes - By reflecting a proportion of the convertor station costs into the non locational TNUoS charge, based on the clear evidence set out in the

	Workgroup report that certain cost components of the convertor station are equivalent to onshore AC items, this is better than the Baseline. Therefore it does better meet Applicable Objective (b) than the Baseline.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment by the TO(s), in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[HVDC] Specific EF; specific *x*% Conv. cost reduction (AC sub)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Baseline.
(b)	Yes - By reflecting a proportion of the convertor station costs, based on actual figures (if available, or generic if not) into the non locational TNUoS charge, based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station are equivalent to onshore AC items, this is better than the Baseline. Therefore it does better meet Applicable Objective (b) than the Baseline.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment by the TO(s) in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[Islands] Specific EF 100% Conv+100%Cable (original)**
(a)	No – As the locational TNUoS charge includes items that should not be recovered locationally (see (b) below) this is harmful to competition in generation. Therefore it does NOT better meet Applicable Objective (a) than the Baseline.
(b)	No – By reflecting the full 100% of the convertor station costs into the locational TNUoS charges even though there is clear evidence, as set out in the Workgroup report, that certain cost components of the convertor station are equivalent to onshore AC items which would not be recovered via the locational TNUoS charges this means that this is not better than the Baseline. Therefore it does NOT better meet Applicable Objective (b) than the Baseline.
(c)	No - We believe that the approach to the HVDC expansion factor outlined in the CMP213 Original proposal, i.e. 100% convertor station costs and 100% cable costs; does not match the developments in the *transmission licensees' transmission businesses.* Therefore it does NOT better meet Applicable Objective (c) than the Baseline.

Overall	No – for the reasons set out above.

Objective	**[Islands] Specific EF; generic 30% Conv+100%Cable (AC sub + STATCOM)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Baseline.
(b)	Yes - By reflecting a proportion of both the convertor station costs and the STATCOM costs into the non locational TNUoS charge, based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station and STATCOM are equivalent to onshore AC items; this is better than the Baseline. Therefore it does better meet Applicable Objective (b) than the Baseline.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment by the TO(s) in HVDC transmission circuits (including STATCOM) we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[Islands] Specific EF; generic 50% Conv+100%Cable (AC sub)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Baseline.
(b)	Yes - By reflecting a proportion of the convertor station costs into the non locational TNUoS charge, based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station are equivalent to onshore AC items, this is better than the Baseline. Therefore it does better meet Applicable Objective (b) than the Baseline.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment by the TO(s) in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[Islands] Specific EF; specific *x*% specific Conv. cost reduction (AC sub)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Baseline.

(b)	Yes - By reflecting a proportion of the convertor station costs, based on actual figures (if available, or generic if not) into the non locational TNUoS charge; based on the clear evidence set out in the Workgroup report that certain cost components (of the convertor station) are equivalent to (onshore) AC items; this is better than the Baseline. Therefore it does better meet Applicable Objective (b) than the Baseline.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment, by the TO(s), in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

VOTE TWO – BETTER THAN ORIGINAL

Objective	**[Extent of sharing] No Diversity**
(a)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
(b)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
(c)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
Overall	Neutral – for the reasons set out above.

Objective	**[Extent of sharing] Diversity Method 1**
(a)	No – The complexity associated with Method 1 together with other factors including the lack of a solution to charges in Negative Zones and the introduction of undue discrimination into the methodology with respect to the unequal treatment of certain plant as 'low carbon' (and others as 'carbon') mean that Method 1 is detrimental to effective competition in the generation of electricity. Therefore it does NOT better meet Applicable Objective (a) than the Original.
(b)	Neutral – Whilst there are some cost-reflective enhancements, compared to the Original, with Method 1, there are also some detrimental attributes, in terms of cost reflectivity with Method 1, for example the lack of a solution to charges in Negative Zones and the introduction of undue discrimination into the methodology with respect to the unequal treatment of certain plant as 'low carbon' (and others as 'carbon'). This means that Method 1 is neutral as regards better reflecting costs.
(c)	No - The transmission businesses are developed in line with GB SQSS. This planning approach does not incorporate "Diversity". We believe that the approach to sharing outlined in the CMP213 Original proposal, i.e. no diversity, best matches the developments in the *transmission licensees' transmission businesses.*
Overall	No – for the reasons set out above. For the avoidance of doubt, these dis-

	benefits associated with Method 1, in terms of Applicable Objectives (a) and (c), outweigh any benefits (in terms of Applicable Objectives (a), (b) and (c)) arising from either the 'Form of Sharing', 'HVDC' or 'Island' components.

Objective	**[Extent of sharing] Diversity Method 2**
(a)	No – The complexity associated with Method 1 is greater with Method 2 which together with other factors including the introduction of undue discrimination into the methodology with respect to the unequal treatment of certain plant as 'low carbon' (and others as 'carbon') mean that Method 2 is detrimental to effective competition in the generation of electricity. Therefore it does NOT better meet Applicable Objective (a) than the Original.
(b)	No – Method 2 has a number of significant detrimental attributes, in terms of cost reflectivity, including the application of an arbitrary '50%' figure as well as the unequal treatment of certain plant as 'low carbon' (and others as 'carbon'). Therefore it does NOT better meet Applicable Objective (a) than the Original.
(c)	No - The transmission businesses are developed in line with GB SQSS. This planning approach does not incorporate "Diversity". We believe that the approach to sharing outlined in the CMP213 Original proposal, i.e. no diversity, best matches the developments in the *transmission licensees' transmission businesses.*
Overall	No – for the reasons set out above. For the avoidance of doubt, these dis-benefits associated with Method 2, in terms of Applicable Objectives (a) (b) and (c), outweigh any benefits (in terms of Applicable Objectives (a), (b) and (c)) arising from either the 'Form of Sharing', 'HVDC' or 'Island' components.

Objective	**[Extent of sharing] Diversity Method 3**
(a)	No – The complexity associated with Methods 1 and 2 are greater with Method 3 which together with other factors including the introduction of undue discrimination into the methodology with respect to the unequal treatment of certain plant as 'low carbon' (and others as 'carbon') mean that Method 3 is detrimental to effective competition in the generation of electricity. Therefore it does NOT better meet Applicable Objective (a) than the Original.
(b)	No – Method 3 has a number of significant detrimental attributes, in terms of cost reflectivity, including the application of an arbitrary '50%' figure as well as the unequal treatment of certain plant as 'low carbon' (and others as 'carbon'). Therefore it does NOT better meet Applicable Objective (a) than the Original.
(c)	No - The transmission businesses are developed in line with GB SQSS. This planning approach does not incorporate "Diversity". We believe that the approach to sharing outlined in the CMP213 Original proposal; i.e. no diversity, best matches the developments in the *transmission licensees' transmission businesses.*
Overall	No – for the reasons set out above. For the avoidance of doubt, these dis-

	benefits associated with Method 3, in terms of Applicable Objectives (a) (b) and (c), outweigh any benefits (in terms of Applicable Objectives (a), (b) and (c)) arising from either the 'Form of Sharing', 'HVDC' or 'Island' components.

Objective	**[Form of Sharing] YR - ALF historic specific (5 years)**
(a)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
(b)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
(c)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
Overall	Neutral – for the reasons set out above.

Objective	**[Form of Sharing] YR - Hybrid**
(a)	Yes – The application of a 'usage' element based on the Users' actual ALF (over a set period) into TNUoS charges to reflect Users usage of the transmission system, not only better reflects costs (see (b) below) but also better facilitates competition in the generation of electricity. Therefore, with respect to the Original, this better facilitates Applicable Objective (a).
(b)	Yes – The application of a 'usage' element based on the Users' actual ALF (over a set period) into TNUoS charges to reflect Users' usage of the transmission system, compared with the Baseline, '100%' ALF demonstrably better reflects the cost of using the transmission system onto those that give rise to those costs. Having a forecast option is a further, beneficial, enhancement in terms of cost reflectivity. Therefore, with respect to the Original, this better facilitates Applicable Objective (b).
(c)	Neutral.
Overall	Yes – for the reasons set out above.

Objective	**[HVDC] Specific EF 100% Conv+100%Cable (original)**
(a)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
(b)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
(c)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
Overall	Neutral – for the reasons set out above.

Objective	**[HVDC] Specific EF; generic 40% Conv+100%Cable (AC sub + QB)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Original.
(b)	Yes - By reflecting a proportion of both the convertor station costs and the

	QB costs into the non locational TNUoS charge, based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station and QBs are equivalent to onshore AC items; this is better than the Original. Therefore it does better meet Applicable Objective (b) than the Original.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment, by the TO(s), in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[HVDC] Specific EF; generic 50% Conv+100%Cable (AC sub)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Original.
(b)	Yes - By reflecting a proportion of the convertor station costs into the non locational TNUoS charge; based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station are equivalent to onshore AC items, this is better than the Original. Therefore it does better meet Applicable Objective (b) than the Original.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment by the TO(s) in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[HVDC] Specific EF; specific *x*% Conv. cost reduction (AC sub)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Original.
(b)	Yes - By reflecting a proportion of the convertor station costs, based on actual figures (if available, or generic if not) into the non locational TNUoS charge; based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station are equivalent to onshore AC items, this is better than the Original. Therefore it does better meet Applicable Objective (b) than the Original.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment, by the TO(s), in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[Islands] Specific EF 100% Conv+100%Cable (original)**
(a)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
(b)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
(c)	Neutral - As the Original includes this attribute, then with respect to better than the Original it is neutral.
Overall	Neutral – for the reasons set out above.

Objective	**[Islands] Specific EF; generic 30% Conv+100%Cable (AC sub + STATCOM)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Original.
(b)	Yes - By reflecting a proportion of both the convertor station costs and the STATCOM costs into the non locational TNUoS charge, based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station and STATCOM are equivalent to onshore AC items; this is better than the Original. Therefore it does better meet Applicable Objective (b) than the Original.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment by the TO(s) in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

Objective	**[Islands] Specific EF; generic 50% Conv+100%Cable (AC sub)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Original.
(b)	Yes - By reflecting a proportion of the convertor station costs into the non locational TNUoS charge, based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station are equivalent to onshore AC items; this is better than the Original. Therefore it does better meet Applicable Objective (b) than the Original.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment by the TO(s) in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.

Overall	Yes – for the reasons set out above.

Objective	**[Islands] Specific EF; specific *x*% specific Conv. cost reduction (AC sub)**
(a)	Yes - As the non locational TNUoS charge includes items that should be recovered non locationally (see (b) below) this is beneficial to competition in generation. Therefore it does better meet Applicable Objective (a) than the Original.
(b)	Yes - By reflecting a proportion of the convertor station costs, based on actual figures (if available, or generic if not) into the non locational TNUoS charge, based on the clear evidence set out in the Workgroup report that certain cost components of the convertor station are equivalent to onshore AC items, this is better than the Original. Therefore it does better meet Applicable Objective (b) than the Original.
(c)	Yes – Whilst this approach still does not fully reflect the case for investment by the TO(s) in HVDC transmission circuits we believe that this approach to the HVDC expansion factor, as outlined in this proposal, does better match the developments in the *transmission licensees' transmission businesses* than the approach outlined in the Baseline.
Overall	Yes – for the reasons set out above.

CUSC Code Administrator Consultation Response Proforma

CMP213 – Project Transmit TNUoS Developments

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on the 9 May 2013** to cusc.team@nationalgrid.com. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the CUSC Modifications Panel when it makes its recommendation to the Authority.

These responses will be included in the Final CUSC Modification Report which is submitted to the CUSC Modifications Panel.

Respondent:	Nick Kay and Nick Oppenheim on behalf of Uisenis Power Limited
Company Name:	Uisenis Power Limited
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	**HVDC and Islands** The HVDC parallel circuits (the 'bootstraps') and the HVDC island links will be implemented as extensions to the onshore transmission network. As such any charging methodology adopted must be consistent with current onshore transmission charging to ensure that all onshore generators, including those on the Scottish Islands and to the North of the bootstraps, are able to compete on an equal footing with those to the South of the bootstraps. This is essential to facilitate effective competition between generators, in line with the CUSC objectives. We remain convinced that the correct charging methodology for HVDC would be to recover the costs of all of the fixed assets through the residual charging element (ie. all of the converter station costs). However we are encouraged that alternatives have been developed by the Workgroup that would see elements of the fixed converter costs excluded from the specific circuit expansion factors and recovered through the residual charging element. HVDC can offer significant technical and environmental benefits over traditional AC solutions, facilitating long distance underground transmission without the need for costly intermediate substations and compensation equipment. Indeed HVDC converters are able to help compensate the AC network, offering system operators a level of dynamic control of the network to which it is embedded. Significant fixed cost elements are avoided, as is the need for long overhead lines, hugely reducing environmental impact. HVDC can also be more readily

	installed subsea. The use of new HVDC technology in the transmission network should therefore be embraced and not hindered by a charging methodology that simply passes 100% of the costs to the connecting generators. This is particularly important as the transmission network is facing a period of significant development. The benefits of HVDC mean it is now being selected by Transmission Owners for many major onshore reinforcement projects, such as the bootstraps and the island links, as the best available technology when considering system performance, cost and environmental impact. The baseline charging methodology does not address this new technology. The original proposal put forward a methodology using offshore charging as a precedent. However this could see HVDC connected generator charges higher than had inferior, and potentially more costly traditional AC solutions been implemented. This would distort competition creating groups of generators with different interests on the network. It would also disadvantage a large proportion of low carbon development. The current AC onshore network charging methodology does not include distance related transmission network costs, such as substations, in the calculation of expansion factors. Therefore, the proportion of HVDC converter station costs which can be related to AC substation equipment should be removed from the calculation of the expansion factor. We would agree with the evidence put forward in the Workgroup Report that approximately half the costs of an HVDC converter are akin to AC substation equipment and should therefore be removed from the expansion factor. Further evidence in the Workgroup Report (Annex 5, 5.32 and Annex 14.4) highlights that converters are supplied under turnkey contracting arrangements with specific cost details difficult to obtain. Moreover the evidence shows that whilst the overall costs of converters can vary depending on factors such as capacity and market conditions, the basic make-up of a converter station is consistent, comprising approximately 50% AC transmission equipment and 50% DC switching equipment. As we have mentioned above, HVDC technology offers significant advantages over traditional AC solutions. This is especially the case for VSC converter technology, and is recognised in the Workgroup Report (sections 6.43 to 6.46 and Annex 14.6). These benefits can be quantified by comparison to equivalent fixed AC equipment at an additional 20% of the costs of VSC converters and 10% of the costs of CSC converters. It is evident that these additional costs should also be removed from the HVDC expansion factor.

	We should therefore see a total of 70% (generic 50% plus 20%) of the costs of VSC converters and 60% (generic 50% plus 10%) of the costs of CSC converters excluded from the specific circuit expansion factors and recovered through the residual charging element. We believe this would be the methodology for HVDC that would be most consistent with current onshore transmission charging. As reflected in the Workgroup Report (section 6.42), there are important differences with offshore. Specific commercial arrangements have been put in place to help facilitate the development of offshore wind technology, including higher levels of policy support and the OFTO arrangements in respect of transmission connections. Offshore connections tend to be radial links to individual generator stations. As such we believe the original proposal should not use offshore as a precedent for onshore transmission charging methodology. **Sharing** In terms of sharing we believe that a methodology based on a proxy of actual generator Annual Load Factor (ALF), as used in the original proposal, provides a good balance between complexity and practicality whilst also improving cost reflectivity when compared with the baseline. As such it is a sensible development to the baseline. We believe that the various 'diversity' alternatives considered are overly complex and do not provide a robust basis for a bid priced based solution. Whilst the introduction of diversity could help improve cost reflectivity we believe that the reduced level of transparency and predictability of TNUoS tariffs would make it difficult for developers to make efficient economic decisions. In addition, each of the diversity options will increase charging volatility particularly for generators in the North and the Scottish Islands, the very areas where renewable resources are most abundant. The actions of other users, such as reducing TEC or closing down generators, could result in significant increases in TNUoS charges. This volatility, coupled with higher charges, would undermine competition and create a significant barrier to the development of renewable based projects in these important geographical areas. Considering the diversity options specifically: • We believe the Diversity 1 is an improvement to the baseline in that it recognises the impact of load factor, without looking to cap the level of sharing. However, on balance, the complexity of Diversity 1 outweighs the cost reflectivity benefit and therefore we do not believe it is a significant improvement to the original proposal.

	• Diversity 2 and 3 do not provide an accurate reflection of sharing on the transmission system as we do not believe that sharing should be capped at 50%. We would therefore not see either Diversity 2 or 3 providing any improvement. Whilst the diversity options are complex they still fall short in assuming that sharing only occurs between carbon and non-carbon generation. The work undertaken by Heriot-Watt University has demonstrated that this assumption is wrong, evidencing that that sharing does in fact occur between low carbon generators. We are therefore of the view that the alternatives put forward on diversity would not accurately reflect the level of sharing on the network. Sharing between low carbon generators would need to be incorporated into any diversity methodology. However we are encouraged that sharing between low carbon generators has been recognised on local circuits with the inclusion of the Counter Correlation Factor (CCF) into the original proposal. **Conclusion** We would support the alternatives that remove elements of the HVDC converter costs. All of these are an improvement to the baseline and the original proposal. However, of those put forward, the alternative most in line with the CUSC objectives would exclude a generic 70% (VSC) and 60% (CSC) of the converter costs from the specific circuit expansion factors and recover these through the residual charging element. This methodology would be most consistent with current onshore transmission charging. It provides a more level playing field for onshore generators on the network, and thus helps facilitate competition on a more equal footing. Also it would provide the greatest degree of stability and predictability for transmission system users. In terms of sharing we believe that the original proposal achieves the best compromise between cost-reflectivity and complexity in reflecting the differential impact of generators into the charging methodology. We would consider that the original proposal incorporating any of the WACMs which remove elements of the HVDC converters costs as an overall improvement. It is interesting to note that graph A15.25 of the Workgroup Report highlights that the impact on consumer bills of the original proposal with 50% converter costs removed would compare favourably against the baseline and all diversity options considered.

	Overall we believe that WACM 7, which secured the most Workgroup votes of the alternatives considered, would be the best outcome to meet the Applicable CUSC objectives. It would best facilitate effective competition, achieving the best balance between cost reflectivity and stability. Overall, it would provide a use of system charging methodology that properly takes account of the developments in transmission licensees' transmission businesses, as far as is reasonably practicable.

Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We would support implementation in as soon as is practicable. Although this is tight, we believe that April 2014 is attainable.
Do you have any other comments?	It is understood that the remit of CMP213 is to ensure a charging methodology is developed to best facilitate the applicable CUSC objectives. With regard to Project Transmit however, we understand this has the aim of ensuring that appropriate arrangements are in place to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers. From the evidence put forward in the Workgroup Report it would appear that a number of the methodologies and alternatives developed under CMP213 would put significant barriers in the way of achieving this aim. These alternatives would create uncertainty, volatility and higher prices for those renewable generators located in the most suitable areas. They would also favour traditional, costly and less suitable AC transmission technology. However we believe this would not be the case for those alternatives based on the original proposal and which remove elements of the HVDC converters costs. We believe that these would be in line with Project Transmit by: • helping facilitate renewable generation in the most suitable areas where resource is most abundant • helping facilitate the use of new sophisticated and best suited HVDC transmission technology • providing most value for money for consumers. WACM 7 in particular, not only best facilitates the CUSC objectives, but would also seem most in line with the aims of Project Transmit.