nationalgrid

Stage 06: Final CUSC Modification Report

- Volume 1

Connection and Use of System Code (CUSC)

CMP213 Project TransmiT TNUoS Developments

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

This proposal seeks to modify the CUSC so that the TNUoS charging methodology recognises that the impact on incremental transmission network cost varies for generators with different characteristics as well as location; that HVDC circuits that parallel the main transmission network are represented within the charging methodology; and to extend the charging methodology to include island transmission connections comprised of sub-sea cable technology.

Published on: **14th June 2013**

The Panel recommends:
That WACMs 2, 19, 21, 23, 26, 28, 30 and 33 better facilitate the Applicable CUSC Objectives.

High Impact:
Generators

Medium Impact:
None

Low Impact:
All other CUSC parties liable for TNUoS charges

Contents

Any Questions?

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About this document

This is the Final CUSC Modification Report which contains details of the Panel Vote. It has been prepared and issued by National Grid as Code Administrator under the rules and procedures specified in the CUSC. The purpose of this document is to assist the Authority in their decision whether to implement CMP213.

Document Control

Version	Date	Author	Change Reference
1.0	14th June 2013	Code Administrator	Version for Submission to Authority

1 Summary

1.1 This document summarises the deliberations of the Workgroup and describes the CMP213 Modification Proposal, raised by National Grid Electricity Transmission (NGET) in fulfilment of the Project TransmiT Significant Code Review (SCR) Direction issued by Ofgem (the Authority). It has been prepared in accordance with the terms of the Connection and Use of System Code (CUSC). An electronic copy can be found on the National Grid website, along with the CUSC Modification Proposal Form.

Background

1.2 Project TransmiT was Ofgem's independent and open review of transmission charging and associated connection arrangements. The stated aim of Project TransmiT was to ensure that arrangements were 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.

1.3 The electricity transmission charging element of the Project TransmiT process commenced with reports from various academic experts and which led to an Ofgem initiated Significant Code Review (SCR) and the establishment of an SCR Technical Working Group which investigated several different approaches to the calculation of Transmission Network Use of System (TNUoS) tariffs. This was supported by economic analysis undertaken by Redpoint on behalf of Ofgem. This process led the Authority to rule out a socialised approach to transmission charging and set out that incremental improvements to the existing Investment Cost Related Pricing (ICRP) approach were likely to represent the best way forward.

1.4 On the 25th of May 2012, the Authority directed NGET[1] to raise a Modification proposal to the CUSC to ensure that the TNUoS methodology:

i) Better reflects the costs imposed by different types of generators on the electricity transmission network (a.k.a. network **sharing**);

ii) Takes account of the development of **High Voltage Direct Current (HVDC) circuits** that will run parallel to the AC transmission network; and

iii) Takes account of potential **island connections** comprised of sub-sea cable technology, such as those currently being considered in Scotland

1.5 The CMP213 CUSC Modification Proposal was submitted to the CUSC Modifications Panel (the Panel) for their consideration on 29th June 2012. A copy of the CUSC Modification Proposal can be found in Annex 2.

1.6 The Panel determined that the CUSC Modification Proposal should be considered by a Workgroup and that they should report back to the CUSC Modifications Panel following a period for the Workgroup consultation.

Workgroup Process and Consultation

1.7 The CMP213 Workgroup held their first meeting on the 10th of July 2012 and agreed the Terms of Reference on 24th of July 2012. A copy of the Terms of Reference is provided in Annex 1. Over the subsequent 29 meetings the Workgroup has considered the issues outlined in the CUSC Modification Proposal and worked through the Terms of Reference. The Workgroup have also considered potential options and alternatives to the Original proposal (i.e. the proposal submitted by NGET to the Panel on the 29th June 2012).

[1] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20direction%2025%20May%202012.pdf

1.8 The Workgroup consultation closed on 15th January 2013 and 21 responses were received. These responses can be found in Volume 3. Following on from this consultation the Workgroup considered the views expressed in the responses, carried out further analysis, the Original was agreed by the Proposer and the Workgroup agreed the WACMs. These were then assessed against the Applicable CUSC objectives.

1.9 This Code Administrator Consultation closed on 9th May 2013 and 26 responses were received. These responses can be found in Volume 3 and a summary of them can be found in section 12.

1.10 This CUSC Modification Report has been prepared in accordance with the terms of the CUSC. An electronic copy can be found on the National Grid website at www.nationalgrid.com/uk/Electricity/Codes, along with the CUSC.

Rationale for CMP213

1.11 The underlying principle behind TNUoS charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of providing them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs. The ongoing application of this rationale was supported by the conclusion of the Ofgem Project TransmiT SCR process.

1.12 As a greater proportion of variable, renewable generation connects to the transmission network, the output of many conventional generators has also become more variable in nature. As generators of different technology types change the way in which they use the transmission network, the nature of transmission network investment planning has also altered to ensure efficient investment is undertaken. This is exemplified in the recent changes to the National Electricity Transmission System Security and Quality of Supply Standards – NETS SQSS (GSR-009) and the increasing amount of transmission investment justified on the basis of avoided future constraint costs (i.e. outside of the deterministic NETS SQSS standards) using cost benefit analysis methods.

1.13 These changes in transmission network investment planning, implying increased sharing of transmission capacity by generators with different characteristics, have yet to be reflected into the Investment Cost Related Pricing (ICRP) methodology used to calculate TNUoS tariffs. This change in approach for investment in transmission network capacity driven by generators does not affect network investment for demand.

1.14 Linked to these changes is the proposed use of transmission network technologies not currently in widespread application across the system. In order to improve predictability of future TNUoS tariffs and ensure the methodology used to calculate tariffs incorporates these HVDC and sub-sea technologies in a cost reflective manner, updates to the existing TNUoS methodology are required.

1.15 In line with the SCR Direction from the Authority, and as set out in paragraph 1.4, the CMP213 Modification proposal is comprised of three aspects addressing the issues outlined above. These aspects are designed to enhance the cost reflectivity of the charging methodology, keep it in line with developments in the transmission system and hence promote effective competition in the electricity market.

High Level Summary of the Original and Workgroup Discussions

1.16 For the avoidance of doubt, the CMP213 Original Modification proposal is referred to as the "Original" and the "Original proposal" hereafter.

1.17 The three aspects of the Original proposal are summarised in Table 1, below

Summary of Original Proposal		
1. Sharing – Improving the incremental cost signal		
i)	Alignment with changes to the NETS SQSS	When calculating background power flows: - split Transport Model into 2 backgrounds; Peak Security and Year Round; - scale generation to meet peak demand using NETS SQSS approach for each.
ii)	Differentiation between generators based on characteristics as well as location	When calculating incremental costs: - circuits allocated to one background or the other based on highest flows (commensurate with planning); - two wider locational tariff elements representing the 2 Transport Model backgrounds; - intermittent generation not exposed to the Peak Security element; - Year Round element scaled by a sharing factor (based on generator historic specific annual load factor); - redefine charging definition of MITS node such that radial circuits are classified as local; - apply a Counter Correlation Factor to reflect sharing on radial circuits where designed by a Transmission Owner to include sharing (i.e. transmission capacity built is less than total TEC).
2. HVDC Circuits – Including these circuit types into the methodology		
i)	Incremental power flow calculation	When calculating background power flows: - model HVDC circuit as pseudo-AC circuit; - calculate HVDC circuit flow by apportioning flows with parallel AC circuits, using relative circuit ratings; - average flows across all major system boundaries crossed by the HVDC circuit; - set impedance of the HVDC circuit to achieve this flow.
iii)	Expansion Factor (unit cost) calculation	When calculating expansion factors: - include both converter station costs and cable costs; - create a specific value for each HVDC circuit.
3. Island Connections – Including these sub-sea connections into the methodology		
i)	Local / Wider definition	When classifying island nodes as part of the MITS: - utilise the updated definition; - take account of reduced security, where relevant; - note changes made to radial circuits in section 1 above and implications for island connections.
ii)	Expansion Factor (unit cost) calculation	When calculating expansion factors: - create a specific expansion factor for each AC technology; - for HVDC connections maintain consistency with HVDC approach set out above.

Table 1 – Summary of Original proposal

1.18 Each aspect of the Original proposal is set out in more detail, below.

(i) Sharing

1.19 The sharing aspect of the Original proposal seeks to enhance the cost reflectivity of the incremental cost signal for generation TNUoS tariffs by incorporating recent changes to the NETS SQSS in the model used to calculate that signal. These changes would see the wider locational element of TNUoS tariffs calculated on two separate backgrounds, Peak Security and Year Round. The scaling of generation to meet demand in these two backgrounds is representative of that used when planning the transmission network.

1.20 Incremental costs on a particular transmission circuit would be allocated to one background or the other, depending on which one is deemed to trigger the need for incremental capacity. It is proposed that this trigger is the background (Peak Security or Year Round) leading to the highest power flows on the transmission circuit in question, consistent with the network planning approach.

1.21 When calculating charges for a specific generator the wider locational TNUoS tariff is split into two elements arising from the Peak Security and Year Round backgrounds in the charging model.

1.22 As investment in transmission capacity is currently not planned for intermittent generation under peak electricity demand conditions, intermittent generation plant would not be exposed to the Peak Security element of the TNUoS tariff. However, treatment would continue be linked to the exposure of this type of generation in the NETS SQSS at times of peak electricity demand, such that if the NETS SQSS considerations changed then the treatment in transmission charging would be reconsidered accordingly.

1.23 In order to enhance the existing distance related signal and differentiate between the incremental impact of generation with different characteristics in a simple and transparent manner, the Year Round element of the TNUoS tariff would be multiplied by a sharing factor based on the specific annual load factor (ALF) of each generator. This approach recognises that there are many generation characteristics that have an effect on incremental costs (e.g. fuel price, efficiency, availability, CO_2, subsidies, bid price, offer price, etc.), but opts for a simple proxy in the form of annual load factor which is taken as a representative manifestation of all these characteristics.

1.24 The resulting TNUoS tariff for conventional and intermittent generation would be of the form illustrated in Figure 1, below:

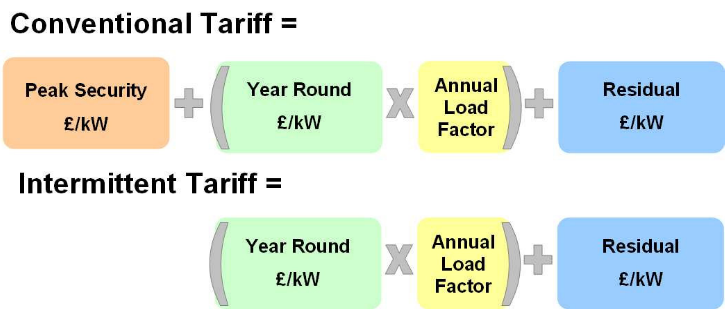

Figure 1 – TNUoS tariffs under the Original proposal

1.25 To reflect the potential for sharing of generation technologies on local radial circuits accounted for by a TO, it is proposed to develop a Counter

Correlation Factor (CCF), and redefine the charging definition of MITS node to ensure all radial circuits are defined as local.

1.26 The Workgroup considered the Original proposal for sharing in detail and have developed several potential alternatives based on the considerations set out in the terms of the Authority's SCR Direction and the specific requests from the CUSC Panel.

1.27 The main aspects of these discussions and developments are set out in Table 2, below.

1. Sharing – Main Areas of Workgroup Discussion		
i)	How charging structures should be applied in areas dominated by one type of generation	- The Original proposal would apply the sharing factor equally to the Year Round element for all wider locational tariffs. - Discussion centred on analysis undertaken by the Workgroup on areas with little diversity of generation plant types. - Potential options and alternatives arising from this analysis would recognise that the relationship between impact on incremental congestion costs and a generator's annual load factor deteriorates in areas with insufficient non-low carbon thermal generation (due to its bid price characteristics).
ii)	How the sharing factor (based on annual load factor) should be calculated	- The Original proposal would calculate the sharing factor based on 5 years historic load factor (using metered output), removing the highest and lowest and averaging the remaining three values. - Discussion centred on what the sharing factor should represent in order to be cost reflective. Some believed that it should reflect network planning assumptions, whilst others believed that it should reflect transmission system usage. - Potential options and alternatives were discussed based on calculating the sharing factor ex-ante or ex-post, whether it should be based on historic or forecast information and whether it should be plant specific or generic.
iii)	Whether intermittent technology types should be exposed to the peak element of the tariff	- The Original proposal would calculate a two part wider locational tariff including Peak Security and Year Round elements, with intermittent generation not being exposed to the Peak Security element to be consistent with the NETS SQSS. - Discussion on what the level of exposure of intermittent plant should be to this tariff element if it was not based on its assumed contribution to the need for transmission network capacity in the planning standards. - Potential options and alternatives were discussed based on some exposure, but the majority of the Workgroup concluded that exposure should be linked to the NETS SQSS assumptions.

Table 2 – Main areas of Workgroup discussion for sharing

1.28 Workgroup discussion focused on the use of generation ALF as a proxy for transmission network investment. Both the NGET Electricity Scenario Illustrator (ELSI) model and a separate generic market model were used to investigate the robustness of the relationship between generator ALF and annual incremental costs in areas with little or no diversity of generation plant type.

1.29 Views in the Workgroup were split between those who believed that the balance between cost reflectivity and simplicity of the TNUoS tariff calculation was optimum in the Original proposal (i.e. using the MITS definition as the boundary) and those who believed that the non existence and deterioration in later years of the relationship between generation annual load factor and annual incremental costs in areas with little generation diversity was such that a potential alternative approach was required.

1.30 Three broad methods were developed by the Workgroup to address the issue of generation plant diversity (and the underlying issue of bid price diversity) as potential options and alternatives. These are summarised in Table 3, below.

Area	Original	Method 1	Method 2	Method 3
	All wider Year Round (YR) shared	YR zonal shared / not shared split	YR zonal shared / not shared split	Single background with zonal sharing factor
Dual background	Yes	Yes	Yes	No
Wider locational tariff components	2	3	3	1
MITS sharing	All YR incremental costs	YR split into shared / not shared	YR split into shared / not shared	All incremental costs with zonal sharing factors
Application of generator specific sharing factor	Yes	Yes; to shared element	Yes; to shared element	No
Diversity calculation	None	Based on deterministic relationship between low carbon / carbon ratio	Based on minimum of low carbon / carbon generation in an area	Based on minimum of low carbon / carbon generation in an area
Method for split of Incremental Costs	None	Zonal boundary length using boundaries of influence	Zonal boundary length using boundaries of influence	Zonal boundary length using boundaries of influence

Table 3 – Potential options and alternatives to address diversity

1.31 The main distinguishing factors between the methods developed include whether or not a two background approach is utilised as the starting point of the calculation and what proportion of MWkms are allocated as shared behind a transmission boundary. This approach would then either lead to a two part (Peak Security + Year Round) or three part (Peak Security + Year Round Shared + Year Round Not-Shared) wider locational element of the TNUoS tariff for generators. Finally, the methods distinguish further whether a generator specific sharing factor would apply to the shared elements or whether a zonal average sharing factor would be applied. In diversity Method 3, only one part wider locational element is employed i.e. just Year Round.

1.32 External expert analysis from Herriot Watt University was presented to the Workgroup prior to Workgroup consultation around whether there is counter correlation between different renewable generation types on Scottish islands. Views of the Workgroup were split as to whether the aforementioned results were evidence of sharing occurring on local transmission circuits or whether these results pointed to the ability of generators to request a TEC lower than their installed generation capacity. Following the Workgroup consultation, a Counter Correlation Factor was developed to take into account any future sharing on local transmission circuits, when it is explicitly accounted for in transmission network planning assumptions.

1.33 The Workgroup also spent time both before and after the Workgroup consultation considering the charging definition of Main Integrated Transmission System (MITS) node and its impact on the wider / local transmission boundary classifications. The Proposer confirmed that a reclassification would form part of the CMP213 Original.

1.34 When considering how the proposed sharing factor (based on generation annual load factor) should be calculated, the views of the Workgroup were split between those who believed that:

a) This factor should be based on an average of five years of historic metered data (with the highest and lowest factors removed) for each Power Station

b) A more generic factor should be employed as reasonably reflective of transmission network planning assumptions and as a simple, predictable and transparent approach

c) The potential for enhanced cost reflectivity from a more dynamic, potentially forecast factor, would outweigh the benefits of simplicity, predictability and transparency.

1.35 Several approaches were considered prior to the Workgroup consultation. Following this, this was narrowed down to both the manner of calculating ALF in the Original, and an option which combined User Forecasting and National Grid calculated ALF (the "hybrid" option).

1.36 When considering if intermittent generation plant types (e.g. wind, wave or solar generation) should be exposed to the Peak Security element of the proposed two part tariff in the Original, some in the Workgroup believed that there should be some exposure to this tariff element (for intermittent generation). However, the majority of the Workgroup agreed that, as intermittent generation is currently not considered when planning the need for transmission network capacity for Peak Security, there is little justification for its exposure to this tariff element, although it was noted that all generation has equal access rights to the network at all times including peak.

1.37 A range of other potential options and alternatives were considered by the Workgroup through their discussions. These included anticipatory application of the sharing options and the application of a sharing factor to the residual element of the TNUoS tariff, to name a few.

1.38 A full account of the Workgroup deliberations on the sharing aspect of CMP213 is set out in both Annex 4 (pre Workgroup consultation discussions) and Section 4 (post Workgroup consultation discussions) of this document.

(ii) HVDC

1.39 The HVDC aspect of the Original proposal seeks to ensure that HVDC circuits paralleling the AC transmission network are included in the TNUoS charging calculation in a cost reflective manner. As this technology is not currently in use on the wider transmission network and represents an active, rather than passive (as in AC), network element, the Original proposal deals with both the incremental power flow calculation and expansion factor calculation for these HVDC circuits.

1.40 The incremental cost signal in TNUoS is calculated using a load flow model of the transmission network. The Original proposal would model an HVDC circuit by adjusting its impedance in the load flow in order to achieve a pre-determined power flow through it in the base case.

1.41 In order to calculate the predetermined power flow, the ratings of all transmission circuits that cross each main system transmission boundary paralleled by the HVDC circuit individually are summed, excluding the HVDC circuit itself. Subsequently, the power flow across each transmission boundary without any flow on the HVDC circuit would be used to produce a ratio of power flow to boundary total circuit rating. These ratios can be used to calculate an average for all transmission boundaries that the HVDC circuit crosses.

1.42 As set out above, this average power flow to total circuit rating figure is used to set the impedance of the HVDC circuit to produce the power flow that gives this ratio to the HVDC circuit rating. This calculation has a direct impact on the incremental cost signal.

1.43 In addition, the Original proposal would calculate a specific expansion factor for each HVDC circuit on the transmission system. In calculating this expansion factor both the converter station and cable costs would be included in the unit costs, consistent with the existing offshore arrangements.

1.44 The Workgroup discussed and debated the Original proposal for HVDC circuits in detail and developed some options and alternatives based on the considerations set out in the terms of the Authority's SCR Direction and the specific requests from the CUSC Panel.

1.45 The main aspects of these discussions and developments are set out in Table 4, below.

2. HVDC Circuits – Main Areas of Workgroup Discussion		
i)	Incremental power flow calculation	- The Original would calculate circuit impedance based on setting the power flow through the circuit in the base case as a ratio of relative circuit ratings, averaged across all major system boundaries crossed by the HVDC circuit. - There was minimal discussion on this issue within the Workgroup as the majority of members supported this approach. - Some Workgroup members believed a potential alternative would be for the power flow setting to take place as a ratio of relative circuit ratings on the single most constrained boundary crossed by the HVDC circuit.
ii)	Expansion Factor (unit cost) calculation	- The Original would calculate unique expansion factors for each individual HVDC circuit including both converter and cable costs. - Discussion centred on what aspects of the AC/DC converter costs should be included in the unit cost calculation. - Potential options and alternatives were discussed based on treatment of HVDC as AC onshore technology unit costs, removal of all converter costs and removal of a portion of converter costs.

Table 4 – Main Areas of Workgroup Discussion for HVDC

1.46 Relative to the other aspects of the Original proposal, the Workgroup discussion on HVDC transmission circuits was relatively straightforward.

1.47 The Workgroup agreed that the modelling of an HVDC circuit as a pseudo-AC circuit, representing it as a circuit with impedance in the load flow used to calculate incremental cost signals, was appropriate. The Workgroup also agreed with the approach of using a ratio of relative circuit ratings across major system boundaries in order to calculate that impedance.

1.48 Some members of the Workgroup believed that, rather than taking an average of all the major system boundaries that the HVDC transmission circuit crosses, the ratio of relative circuit ratings should be used on the single most constrained major system boundary on the basis that they believed the definition of the number of boundaries to be an arbitrary one. The Workgroup noted that this would increase the effect of the HVDC circuit on the incremental cost signal.

1.49 The Workgroup spent some time debating and developing potential options and alternatives to the calculation of expansion factors for HVDC transmission circuits. The following methods were developed by the Workgroup to address this issue:

1) Removal of all converter station costs from the expansion factor calculation on the basis that (a) they exhibit similar characteristics as those elements of the AC system which are not included in the locational element of TNUoS and (b) including them was seen by some Workgroup members as targeting an excessive amount of cost at those who benefit from the HVDC transmission circuit and that this may also prevent a number of low carbon generators from connecting and contributing to UK sustainability targets.

2) Removal of some converter station costs from the expansion factor calculation on the basis that:
   a) a significant proportion of the converter station costs (~50%) could be deemed as akin to other AC substation elements not currently included in the incremental cost signal;
   b) a proportion of the converter station costs (~10%) could be discounted on the basis that the converters bring benefits akin to Quadrature boosters that re-direct power flows on the transmission network and thus allow for maximum utilisation of existing capacity;
   c) accepting the arguments above, the actual proportions should be considered on a case by case basis.

3) Treatment of HVDC unit costs as existing AC network unit costs on the basis that some Workgroup members believed that the similarities in cost and incremental capacity provided by these two different elements of transmission network technology were sufficient that they should not be differentiated in the methodology.

1.50 Other potential options and alternatives were considered by the Workgroup through their discussions. These included a review of the overhead factor used in the annuity calculation for the capital costs of various transmission technologies and the global security factor.

1.51 A full account of the Workgroup deliberations on the HVDC aspect of the modification proposal is set out in Annex 5 (pre Workgroup consultation discussions) and Section 5 (post Workgroup consultation discussions) of this document.

(iii) Island connections

1.52 The Scottish island connections aspect of the Original proposal seeks to put in place a methodology for calculating cost reflective TNUoS charges for transmission spurs connecting generation and demand between the Scottish mainland and the Scottish islands of the Western Isles, Orkney and Shetland. The sub-sea transmission network technologies proposed for these connections are not currently included in the expansion factors set out in the charging methodology.

1.53 The Original proposal would calculate new expansion factors for each type of transmission network technology proposed. Where such circuits are comprised of HVDC technology, the charging methodology would be consistent with that for HVDC transmission circuits paralleling the AC transmission network as set out in the HVDC section.

1.54 The Original proposal alters the charging definition of a MITS node (see 4.114-4.126) The consequence is that, with the connections currently proposed, transmission circuits connecting islands to the Scottish mainland classed as 'wider' under the existing definition would be classed as 'local'.

1.55 Any potential for the application of the sharing aspect of the modification proposal to islands is set out in the sharing section of the consultation. As most island connections would now be classed as 'local' for charging purposes, any sharing would be taken account of using the Counter Correlation Factor.

1.56 The Workgroup discussed and debated the Original proposal for Scottish Island connections in detail and developed several options and alternatives based on the considerations set out in the terms of the Authority's SCR Direction and the specific requests from the CUSC Panel.

1.57 The main aspects of these discussions and developments are set out in Table 5, below.

3. Islands – Main Areas of Workgroup Discussion	
i) Local / Wider definition	- Discussion centred on whether Scottish island transmission connection nodes should be classed as MITS, given their characteristics, and whether, if they were classed as MITS, it was right that the sharing factor was automatically applied (the sharing aspect of the debate is covered under the sharing section of the proposal). - The Original proposal would utilise a new charging definition of a MITS node (i.e. local and wider), with all radial transmission spurs including island connections being classed as local. This definitional change would not need to apply to diversity options. - For any islands classed as wider, the Original would apply a two part wider locational tariff to island generators (i.e. Peak Security (for conventional) and Year Round) and the sharing factor would be applied to the Year Round element. - There was agreement amongst Workgroup members that the global security factor should not be applied to portions of radial island transmission connections that have no redundancy in any potential alternatives where the MITS definition is unchanged (i.e. where radial island circuits are classed as MITS).
ii) Expansion Factor (unit cost) calculation	- The Original proposal would calculate specific expansion factors for each AC technology and for each individual HVDC transmission circuit. - Discussion centred on whether generic or specific expansion factors would be most appropriate. - Discussion took place on the benefits of Voltage Source Converters and whether costs relating to this element should be socialised if wider network benefits were proven. - Potential options and alternatives were debated based on using fully generic, partially generic and specific expansion factors.

Table 5 -Main areas of Workgroup discussion for islands

1.58 Whilst debating the scenario where an island transmission connection node becomes part of the Main Interconnected Transmission System (MITS) for charging purposes, the Workgroup considered whether the application of a two part tariff and associated sharing factor would be robust.

1.59 The Workgroup agreed that, where an island connection node is classed as MITS, there would be no justification for not applying a two part wider tariff to island generators. For the Original proposal, where concern was raised regarding the impact of applying generation annual load factor on wider island transmission connections, the Proposer introduced a definitional change to MITS node.

1.60 It was agreed that, in situations were a TO has designed and built a radial transmission circuit to specifically reflect the counter correlation of differing generation technologies, a Counter Correlation Factor would be used to scale the expansion factor of the affected circuit. This would take into account any sharing on local circuits, should this take place in transmission network planning assumptions.

1.61 The Workgroup also considered how to incorporate island connections into the charging methodology under potential alternatives where

- the charging definition of MITS node was changed such that all island connections were classed as wider;
- the charging definition of MITS node was changed such that all island connections were classed as local; and
- the existing definition was maintained.

Prior to the Workgroup consultation, the majority of the Workgroup were in favour of maintaining the existing charging definition of MITS node. After the Workgroup consultation, the definition was changed, by the Proposer, in the Original proposal (see paragraphs 4.115-4.126).

1.62 When considering how expansion factors should be calculated for island connections the Workgroup debated a range of methods between fully generic and project specific. The benefits of Voltage Source Converters and whether cost elements should be socialised to reflect this benefit were discussed in particular with reference to islands. The Workgroup also developed several methods as potential alternatives for dealing with the calculation of expansion factors.

1.63 The Workgroup also discussed the potential for an anticipatory application of the MITS node charging definition to island transmission connection nodes where the System Operator believed that these nodes could become part of the MITS at some point in the future. Some members of the Workgroup did not believe that there was a suitably robust reason for why this approach would be appropriate. Others considered that this approach may have benefits and could be justified.

1.64 A full account of the Workgroup deliberations on the island connections aspect of the modification proposal is set out in Annex 6 (pre Workgroup consultation discussions) and Section 6 (post Workgroup consultation discussions) of this document.

CUSC Modifications Panel's Recommendation

1.65 At the meeting of the CUSC Modifications Panel on 31 May 2013, the Panel voted by majority that 8 of the options out of the Original and the 26 WACMs better facilitate the Applicable CUSC Objectives. The options that received majority Panel support against the Objectives were WACMs 2, 19, 21, 23, 26, 28, 30 and 33. Full details of the Panel vote are provided in Section 10.

National Grid's Opinion

1.66 National Grid was directed by the Authority on the 25th of May 2012 to raise a CUSC modification proposal to ensure that the TNUoS methodology:

i) Better reflects the costs imposed by different types of generators on the electricity transmission network (a.k.a. network sharing);

ii) Takes account of the development of High Voltage Direct Current (HVDC) circuits that will run parallel to the AC transmission network; and

iii) Takes account of potential island connections comprised of sub-sea cable technology, such as those currently being considered in Scotland.

National Grid believes that raising the Original proposal for CMP213 efficiently discharges this direction.

1.67 National Grid recognises the hard work that has been achieved by the Workgroup to further develop our Original proposal and believe that the analysis to refine our proposals for network sharing, reflected in the design of the diversity 1 alternative, provides an increase in the cost reflectivity of the proposal whilst also providing a more flexible solution through implicit management of sharing in peripheral parts of the system. It is acknowledged that Diversity options 2 and 3 also recognise sharing, and so are potentially better than the baseline, however, National Grid have concerns over the proposed limits to sharing in these alternatives and, in regards to Diversity 3, the failure to attribute specific impacts to an individual generators. National Grid also note the additional complexity caused by diversity alternatives, and recognise the relative simplicity of the Original and the benefits this brings to competition. There are also concerns regarding the overall cost reflectivity of a user forecast for a generator's annual load factor as proposed in the hybrid option.

1.68 National Grid welcomes the evidence that has been provided to support a reduction in the converter cost reduction by 50% for both parallel HVDC circuits and island connections comprised of sub-sea HVDC cable technology, and also the reduction of converter costs by a further 10% to reflect the additional operational benefits presented by parallel HVDC circuits.

1.69 An implementation date of April 2014 is achievable, but it is noted that the industry uncertainty until a direction is made. It may therefore be more efficient for the end consumer to implement a solution in April 2015 to avoid a risk premium being applied to energy charges.

1.70 On balance, National Grid's considered view is that WACM16 provides the best overall solution against the Applicable CUSC Objectives.

Workgroup Conclusion

1.71 The Workgroup met on 18th March 2013 to vote on the Original proposal and the potential Workgroup Alternative CUSC Modification (WACM) proposals against the Applicable CUSC Objectives. Prior to this Workgroup vote taking place the Proposer confirmed the Original proposal.

1.72 Prior to this vote taking place, concerns were raised around the timescales for the Workgroup process. This was due to the proximity of the release of the Impact Assessment Modelling results prior to the voting. Those Workgroup members with concerns about this argued that inadequate time had been allowed for the Workgroup to digest the results of the modelling prior to the Workgroup vote taking place, and that this was needed in order to fully assess the Original proposal and the potential WACMs against the Applicable CUSC Objective relating to better facilitating effective competition. Some Workgroup members also argued that in addition to the problem of timescales, the fact that some of the impact assessment results were, in their view, questionable, also necessitated a delay in the vote. Other Workgroup members expressed a counter view that there is always a possibility of delaying a decision until the 'complete' information is available – but given ongoing changes that affect the industry, such as with EMR, the European Network Codes etc., this could imply never making any decision on CMP213 as there will always be uncertainty. The Chair noted that the Impact Assessment Modelling work had always been considered a separate work stream to the main CMP213 Modification proposal assessment (as it is not normally part of the CUSC process) and had been sent on request to the Workgroup to better inform their decision making. The actual modelling went beyond the effect of the Original and Alternative proposals, including wider changes such as to renewable / capacity support mechanisms, along with significant assumptions about future generation and transmission project timelines. Therefore the results could not be taken as an absolute comparison between CMP213 options, more rather a possible direction of travel. On that basis, the Chair confirmed that the Workgroup vote should take place based on the principles of the charging methodology better facilitating the Applicable CUSC Objectives. This would provide the effective charging signals that users would then take account of along with other wider revenue drivers.

1.73 A poll was taken as to whether the vote should be delayed. The majority of the Workgroup agreed that it was appropriate to continue with the vote in order to meet the agreed timelines with Ofgem, and that any concerns with the modelling could be dealt with in stakeholder's responses to the Code Administrator consultation. On that basis, the Chair confirmed that voting should take place based on the principles of the methodology meeting the Applicable CUSC Objectives. A number of members indicated that this approach would affect their voting decisions.

1.74 The Workgroup voted on whether or not the Original and each WACM proposal better facilitated the Applicable CUSC Objectives compared with (i) the baseline and (ii) the Original (with respect to the WACMs). This resulted in the Original and eighteen WACMs receiving majority support for better facilitating one or more of the Applicable CUSC Objectives. In addition, the Chair opted to retain a further eight potential WACMs into full WACMs on the basis that, in his view, they better facilitated the Applicable CUSC Objectives.

1.75 Of the total of twenty eight (the baseline, the Original and twenty six WACMs) neither the baseline, the Original nor a single WACM received majority support as 'best' facilitating the Applicable CUSC Objectives. The WACM that received the most support, as 'best', was WACM 7 which received five votes out of a possible fifteen votes. The CUSC baseline also received five votes as the 'best' option.

Terms of Reference

1.76 As stated in paragraph 1.7, the Workgroup was required to fulfil its Terms of Reference (TOR) set by the CUSC Panel. The Workgroup believes that it has discharged these requirements. TOR a through to j refer to the three main aspects of the proposal and the addressing of these by the Workgroup is stated in the relevant sections of the report for sharing, HVDC and islands. Two general TOR were also raised and have been addressed by the Workgroup as follows (applicable sections of the report are given in brackets for reference):

k) consider and undertake appropriate economic analysis including the Impact on current and future consumers on a national and regional basis (report section 7 and Annex 15)

l) consider and undertake appropriate environmental analysis and review illustrative legal text including an assessment of likely impact on electricity generation carbon intensity (report section 7 and legal text in Volume 4)

2 Why Change?

2.1 This CMP213 Modification Proposal was submitted in order to fulfil the requirements of the Direction issued to NGET by the Authority, arising from the Project TransmiT (TNUoS) SCR process. In line with that Direction, there are three main aspects making up this proposal:

i) Better reflection of the incremental costs imposed by different types of generators on the electricity transmission network within the Investment Cost Related Pricing (ICRP) TNUoS tariff calculation (i.e. network sharing);

ii) Introduction of an approach for including High Voltage Direct Current (HVDC) transmission circuits that parallel the AC transmission network into the TNUoS charging methodology; and

iii) Introduction of an approach for including island connections comprised of sub-sea cable technology such as those proposed for the Western Isles, Orkney and Shetland into the TNUoS charging methodology.

2.2 In accordance with the Project TransmiT SCR Direction, CMP213 is designed to help ensure 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.

2.3 In accordance with the relevant Applicable CUSC Objectives, CMP213 seeks to enhance the cost reflectivity of the TNUoS charging methodology, to keep it in line with developments in the transmission system and hence promote effective competition in the electricity market. These aspects are aligned with the relevant Applicable CUSC Objectives for Section 14 (i.e. the Use of System Charging Methodology).

2.4 In their Direction to NGET the Authority also required that the CUSC Modification proposal developed pursuant to the Direction should maximise value for money to existing and future consumers, be supported by a robust evidence base and in so doing give due consideration to the interests of existing and future consumers in the achievement of sustainable development.

2.5 The transmission network sharing aspect of the proposal incorporates developments in planning the transmission network – namely changes to the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS), which specify technological differences in background conditions for transmission network planning studies; as well as the increasing use of Cost Benefit Analysis to supplement the more deterministic NETS SQSS.

2.6 These aforementioned changes to the planning of electricity transmission network investments are largely driven by increasing volumes of variable (largely low carbon) electricity generation sources in order to meet legally binding UK Government renewable and greenhouse gas emission targets. As these variable sources are supported by conventional, thermal generation in meeting electricity demand at times when variable sources are unavailable, the total installed capacity of generation over and above peak electricity demand increases, leading to the need for developments in the methodologies for planning the transmission network.

2.7 Time bound UK Government renewable and greenhouse gas emission targets have also led to the rapid development of variable sources of generation, often at the extremities of the transmission network where renewable resources are in greater supply. This has led to the need for new and the innovative use of existing transmission technology in order to develop the network in the most cost effective manner. The HVDC transmission circuit and Scottish island transmission connection aspects of the proposal seek to expand the existing TNUoS charging methodology so that it is fit for purpose for these new developments in the transmission system.

2.8 The reasoning behind each of the three aspects of the CMP213 Modification proposal is set out in more detail below.

i) Network Capacity Sharing

2.9 In addition to recovering allowed revenue, Transmission Network Use of System (TNUoS) charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) activity functions of each GB Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences (specifically the NETS SQSS), to provide the capability to allow the flow of bulk transfers of power between connection sites for conditions expected to arise over a year of operation and to provide transmission system security.

2.10 The underlying principle behind TNUoS charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of providing them. Therefore, TNUoS charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective transmission systems.

2.11 This rationale is currently accounted for using the Investment Cost Related Pricing (ICRP) methodology which considers the incremental effect of generation and demand via a DC[2] load flow (DCLF) based "Transport" model. The derivation of the incremental investment costs at different points on the transmission system is currently determined against the requirements of that system at the time of peak demand with all generation scaled uniformly to meet that demand.

2.12 As a greater proportion of variable, renewable generation connects to the transmission network, the output of many conventional generators has also become more variable in nature. As generators of different technology types change the way in which they use the transmission network, the nature of transmission capacity investment planning has also altered to ensure efficient investment is undertaken. This is exemplified in the recent changes to the NETS SQSS (GSR-009[3]) and the increasing amount of transmission investment justified on the basis of avoided future constraint costs (i.e. outside of the deterministic NETS SQSS standards) using cost benefit analysis methods. However, the associated commercial arrangements have yet to fully evolve to reflect these underlying physical changes to the transmission system.

2.13 The industry began a process of reviewing the commercial framework to reflect the aforementioned changes through the Transmission Access Review (TAR) process from 2007 to 2010. Through this process, the possibility of explicitly recognising the differential impact on transmission network costs by generators with different characteristics in terms of (i) charging and (ii) access arrangements was considered. However, this

[2] Note that in this context DC does not refer to direct current as used in HVDC, but rather is industry parlance for the simplified methodology used for calculating the load flow.

[3] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=26&refer=Networks/Trans/ElecTransPolicy/SQSS

process culminated in the Secretary of State rejecting this explicit recognition in favour of a form of Connect and Manage. As a result, this CMP213 Modification proposal does not propose to alter the form of transmission access rights afforded to generators (in the form of Transmission Entry Capacity - TEC) through the UK Government's decision. Rather, it seeks to improve the cost reflectivity of TNUoS tariffs for generators by implicitly recognising that this sharing takes place, and is taken into account in an equally implicit manner in the transmission network investment planning process.

2.14 This CMP213 proposal seeks to recognise the implicit sharing of the wider transmission network (local circuits are generally not planned on the basis of being shared and are therefore not deemed to be shared in the Original) by altering the way in which the wider TNUoS tariff is calculated within the Transport and Tariff model, as it is believed that this would improve its cost reflectivity.

ii) Inclusion of parallel HVDC circuits

2.15 When calculating the wider TNUoS tariff utilising the ICRP Transport and Tariff model, various AC transmission technologies are modelled in the load flow element. This is done in order to reflect the various unit costs of these transmission technologies into the calculation of the locational signal. Whilst overhead lines and cables of different voltage levels are included, no High Voltage Direct Current (HVDC) technology, outside of the offshore charging methodology, is currently taken account of in the load flow model (Offshore assets are not included in the load flow due to their radial nature). With the first of two planned HVDC circuits committed[4], the need to be able to suitably represent these links in the TNUoS charging methodology is imminent.

2.16 Power flows on the existing AC transmission network are dictated by the relative impedance of the individual network components (such as overhead lines and cables). These power flows are replicated in the load flow aspect of the TNUoS tariff calculation. However, in the case of HVDC transmission circuits that parallel the AC transmission network, the power flow is controllable and not dictated solely by the impedance characteristic. Therefore to include HVDC in the load flow aspect assumptions need to be made on how much power will flow on the HVDC transmission circuits relative to the rest of the AC transmission network

iii) Inclusion of sub-sea island connections

2.17 An approach for calculating cost reflective TNUoS charges for transmission spurs connecting generation and demand and comprised of transmission network technology not included in the expansion factors, set out in clause 14.15.47 and 14.15.49 of the CUSC (i.e. sub-sea cables), such as those which may be established between the Scottish mainland and the Scottish islands of the Western Isles, Orkney and Shetland; is not currently included in the TNUoS charging methodology.

2.18 In addition, as the Scottish islands are, for the most part, not currently connected to the electricity transmission network and the transmission network technology, in the form of sub-sea cables, is not in wide spread use across the existing transmission network, there is a significant amount of uncertainty faced by developers of generation projects on these islands. Inclusion of transmission network circuits with the characteristics of the proposed Scottish island links into the TNUoS charging methodology would remove some of this uncertainty in the charging signal.

[4] One on the west coast between Hunterson and Deeside, the other planned on the east coast between Peterhead and Teesside.

3 Solution – The Original Proposal

3.1 The Workgroup began its work with reviewing the Original proposal from NGET as the Proposer. It has been the Workgroup's job to debate, probe and, where appropriate, develop alternatives to the Original proposal.

3.2 This Section provides a summary of the solutions arising out of the Original CMP213 proposal. The detailed discussion on the merits, or otherwise, of the Original proposal, potential options for developments of the Original proposal, and any options for potential alternative(s) are set out in Sections 4, 5 and 6.

3.3 The solutions outlined below are split between the three main aspects of the Original proposal (the background behind each is explained in Section 2):

i) Better reflection of the incremental costs imposed by different types of generators on the electricity transmission network within the Investment Cost Related Pricing (ICRP) TNUoS charge calculation (i.e. network sharing);

ii) Introduction of an approach for including HVDC circuits that parallel the AC network into the TNUoS charging methodology; and

iii) Introduction of an approach for including island connections comprised of sub-sea cable technology into the TNUoS charging methodology.

3.4 This Section explains how the Proposer believes the Original proposal addresses the issues outlined in Section 2 and, as such, do not constitute the views of the Workgroup as a whole which are set out in Section 4.

i) Network Capacity Sharing

3.5 This aspect of the Original proposal seeks to recognise the implicit sharing of the wider transmission network (local circuits are generally not planned on the basis of being shared and are therefore not deemed to be shared, so were not part of the Original proposal) by altering the way in which the wider tariff is calculated within the Transport and Tariff model, and also how it is applied, thus improving its cost reflectivity.

3.6 A high-level summary of the sharing aspect of the Original proposal is set out in Table 6, below.

i. Sharing – Improving the incremental cost signal		
i)	Alignment with changes to the NETS SQSS	When calculating background power flows: - split Transport Model into two backgrounds; Peak Security and Year Round; - scale generation to meet peak demand using NETS SQSS approach for each background.
ii)	Differentiation between generators based on characteristics as well as location	When calculating incremental costs: - circuits allocated to one background or the other based on highest flows (commensurate with planning); - two wider locational tariff elements representing the 2 Transport Model backgrounds; - intermittent generation not exposed to the Peak Security element; - Year Round element scaled by a sharing factor (based on generator specific load factor); - redefine charging definition of MITS node such that radial circuits are classified as local; - apply a Counter Correlation Factor to reflect sharing on radial circuits where designed by a TO.

Table 6 – Summary of sharing aspect of Original proposal

3.7 A more detailed explanation of the network capacity sharing aspect of the Original proposal is included in Annex 4.

Transport Model

3.8 The Original proposal seeks to replace the existing peak background in the Transport Model with two separate background conditions, representing (i) Peak Security and (ii) Year Round conditions respectively. Whilst the existing DCLF in the Transport Model sets up the peak demand background by scaling down the contracted TEC of all generators in Great Britain equally to meet total demand, the Original proposal would set up two peak demand conditions and scale generation differently under each to reflect the values used in the NETS SQSS. Some of these values would be fixed year on year and some would vary depending on the demand level in the year under consideration.

3.9 The values that would have arisen from 2011/12 data are shown in Table 7, below:

Generator Type	TEC	Current Methodology	Peak Security Background	Year Round Background
Intermittent	5,460	65.5%	0%	70%
Nuclear & CCS	10,753	65.5%	72.5%	85%
Interconnectors	3,268	65.5%	0%	100%
Hydro	635	65.5%	72.5%	66%
Pumped Storage	2,744	65.5%	72.5%	50%
Peaking	5,025	65.5%	72.5%	0%
Other (Conventional)	61,185	65.5%	72.5%	66%
Values in grey vary depending on the total demand level, whilst values in black are fixed scaling factors corresponding to those used in the NETS SQSS.				

Table 7 – NETS SQSS Treatment by Plant Type

3.10 In order to ascertain whether the incremental investment driver on a given transmission circuit is related to the Peak Security or Year Round conditions, the power flows on each circuit are compared and a proportion of the circuit is allocated to a given investment driver (i.e. Peak Security or Year Round). It is proposed that the allocation is done on the basis of whole circuits being either Peak Security or Year Round driven, with the background leading to the highest flows on a given circuit dictating its investment driver and allocation. For example, if the flows on a particular transmission circuit are calculated to be 2,000MW in the Peak Security background condition and 1,500MW in the Year Round background condition, then that particular circuit is deemed, according to the Original proposal, to be ‘Peak Security’.

3.11 Once the allocation process (between Peak Security and Year Round) is complete, an incremental MW would be applied at each node in the DCLF model, as occurs in the existing TNUoS charging methodology, in order to establish the effect of that additional MW on the transmission network as a whole. Under this Original proposal, the incremental MW process would occur at each node in turn for both the Peak Security and Year Round conditions, as shown in Figure 2, below:

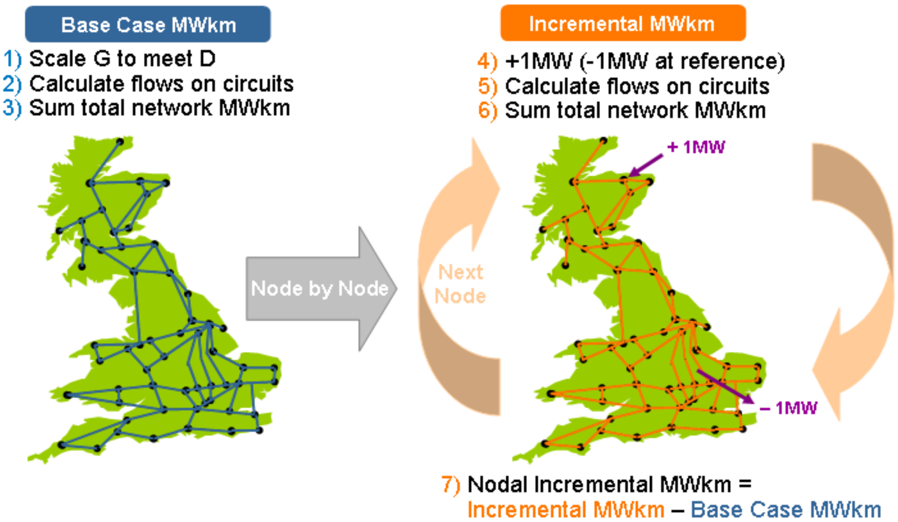

Figure 2 – Calculation of Nodal Incremental MWkm

3.12 Ultimately, this process results in the incremental impact (i.e. MWkm) for each transmission circuit under both Peak Security and Year Round conditions. These total MWkm would subsequently be allocated to either the Peak Security or Year Round elements, based on the aforementioned allocation of a given circuit to an investment driver.

3.13 As the total system MWkm of the Peak Security and Year Round backgrounds is almost the same as the total MWkm under the existing charging methodology, the Proposer believed that this demonstrated that the inclusion and calculation of incremental impacts on a dual background approach, consistent with the NETS SQSS, was robust and consistent with the ICRP approach. Nevertheless, the Proposer also believed that a further step is required in order to make an improvement to the cost reflectivity of this approach when calculating the TNUoS charge, due to the fact that a dual background approach in isolation does not sufficiently address the varying impact of generation plant with different characteristics on incremental costs (i.e. not every incremental MW leads to an incremental MW of transmission network cost). This further step is explained below.

3.14 As the majority of transmission investment is no longer planned on a deterministic basis for peak demand conditions and is increasingly planned using cost benefit analysis techniques for conditions expected to occur across all times of the year, the Original proposal recognises that the impact of an incremental MW on the need for transmission network capacity varies depending on the type and characteristics of generation, as well as its size and location in relation to the existing GB transmission network.

3.15 Due to the nodal granularity of incremental costs in the Transport Model, this recognition of generators' characteristics occurs in the Tariff model, where nodal costs are used to create zonal weighted averages, in order to align with the zonal granularity of wider TNUoS tariffs. This is explained in more detail, below.

Tariff Model

3.16 The Tariff model utilises the nodal incremental MWkm and the unit cost of these MWkms (i.e. the expansion constant and expansion factors) in order to calculate the locational signal, which forms part of the wider TNUoS tariff.

3.17 This is achieved by first averaging the nodal incremental impact across a TNUoS zone using the existing zoning criteria and a demand weighted average of all nodes. The resulting nodal incremental MWkm are multiplied by the expansion constant (EC) (£/MWkm) and the global locational security factor (currently 1.8) to achieve the zonal wider locational (TNUoS) tariff. This is carried out for both the Peak Security and Year Round backgrounds, leading to two separate elements of the wider locational tariff.

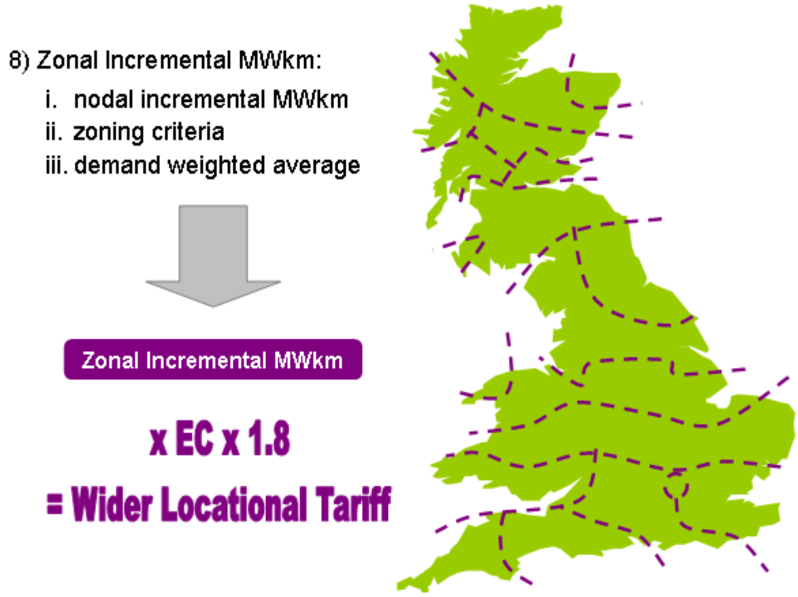

Figure 3 – The Zonal Wider Locational Tariff

3.18 The result of this process is a two part locational element of the wider TNUoS tariff: (Peak Security £/kW) and (Year Round £/kW).

3.19 For the Peak Security element of the TNUoS tariff, it is proposed to maintain the existing uniform treatment of generation, with the exception that the tariff of intermittent plant (e.g. a Power Station using an Intermittent Power Source, as defined in the Grid Code) would currently be scaled to 0% in recognition of the assumptions made, by the TOs, when planning transmission network capacity (i.e. according to the NETS SQSS, to which TOs are obliged to plan and operate their networks through their Transmission Licence, no transmission network capacity is built for intermittent generation on the MITS in order to secure demand at peak demand conditions). This scaling factor would be linked to the NETS SQSS, such that if this factor changed in future, the TNUoS charging methodology would also change.

3.20 This Original proposal would scale the Year Round element of the TNUoS tariff of each generator depending on its impact on the transmission network, using a sharing factor as detailed below.

3.21 Explicit commercial arrangements are not in place that provide Transmission Licensees with information to assess the impact on the need for transmission network investment arising from an individual generator when planning investment using non-deterministic; i.e. cost benefit analysis; methods. Therefore implicit assumptions over input prices (fuel, CO_2, subsidy, etc.) and generator characteristics (efficiency, availability, etc.) relative to the remainder of the market are made by them. The Proposer believes that these detailed implicit assumptions alone are not sufficiently robust in order to calculate TNUoS tariffs. This belief is corroborated by the extensive industry debate undertaken during the Transmission Access Review (TAR) process where various options were considered.

3.22 In order to remain cost reflective, any proposed sharing factor needs to be reflective of the implicit assumptions made when planning transmission network capacity, as it is these assumptions that ultimately lead to the costs that the TNUoS tariff is attempting to reflect. This Original proposal puts forward a form of generator specific sharing factor. This is based on a Power Station's annual load factor (ALF) averaged over 5 years' historic output. The

Proposer sees this as representative of the assumptions made by the TOs, when planning transmission investment for the addition or removal of generation in a given part of the transmission network.

3.23 The use of a Power Station's ALF, as a readily quantifiable manifestation of all the aforementioned detailed characteristics of a generator, was deemed a suitable proxy by the Proposer for use in improving the cost reflectivity of the existing ICRP approach to calculating TNUoS tariffs (i.e. to allow for differentiation between the incremental impact of one generator compared to another). Whilst using a generation ALF is recognised to be a simplification, and charging on more detailed aspects of a generator's characteristics may result in a TNUoS tariff that is more cost reflective, the Proposer believed the proposed CMP213 Original approach represented an appropriate balance between simplicity and cost reflectivity of the TNUoS tariff calculation.

3.24 The detail of the aforementioned TNUoS tariff calculation process is explained further within Annex 8.

3.25 Once the locational elements of the tariff have been calculated, the Tariff model also calculates the non-locational, residual element to ensure that the total allowed revenue is recovered in the proportion of 27% from generators and 73% from demand Users of the transmission network. Together the locational and residual elements of the tariff form the wider TNUoS tariff in the existing charging methodology.

3.26 Under the Original proposal, the structure of the wider TNUoS tariff would change to mirror the change to two backgrounds in the Transport Model, and a two part tariff such that the locational element is split into a Peak Security element and a Year Round element as set out above. As a result, the TNUoS charge for an individual generator arising from the wider element of the annual TNUoS charge would be calculated as follows (noting that intermittent generation are not exposed to the Peak Security element):

[(Peak Security £/kW) + (Year Round £/kW x Sharing Factor) + (Residual £/kW)] x TEC kW = £ wider TNUoS charge

3.27 For the avoidance of doubt, the charging methodology for calculating demand TNUoS charges would be based on the existing approach. Whilst demand tariffs would also be calculated on both a Peak Security and Year Round background, the resultant tariffs are combined and multiplied by the same charging base as under the existing TNUoS charging methodology (due to the fact that investment in transmission network capacity for demand is not affected by the characteristics of that demand, as is the case with generation), thus leading to only minor differences in tariffs as a result of a small number of transmission circuits that change flow direction between the two backgrounds. In other words CMP213 (either the Original or any WACM(s)) will have only a minor impact on demand TNUoS tariffs.

3.28 The Proposer believed that a change in the calculation of generation TNUoS tariffs and only minor changes to demand TNUoS tariffs is consistent with the drivers for change outlined in Section 2 "Why Change", which points to changes in the characteristics of generators and their resultant use of the transmission network due to the UK Government's environmental legislation, amongst other drivers. It was noted qualitatively that, despite progress in this area, electricity demand is still largely price inelastic (noting that there has been some demand reduction among large users in some areas of the GB system), the characteristics of demand has not altered such that its impact on the incremental cost of transmission has not changed.

Post-Workgroup additions to the Original proposal

3.29 After the Workgroup consultation, to address issues around sharing on radial transmission circuits, the Proposer added a Counter Correlation Factor (CCF) to the Original proposal as follows (full description in 4.105-4.113):

$$CCF = \frac{D_{min} + T_{cap}}{G_{cap}}$$

Where D_{min} = minimum annual net demand (MW) supplied via that transmission circuit in the absence of that generation using the circuit
T_{cap} = transmission capacity built (MVA)
G_{cap} = aggregated TEC of generation using that transmission circuit
And where the CCF is capped at 1, i.e. only comes into effect where there is sharing.

3.30 In order to address issues with the local/wider definition for MITS nodes highlighted prior to the Workgroup consultation, the Proposer also confirmed that the Original would contain a revised definition for MITS, for charging purposes only, as follows (full description in 4.114-4.126):

Main Interconnected Transmission System (MITS) nodes are defined *from a charging perspective* as:

1) Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
2) connections with more than 4 transmission circuits connecting at the site.

*Other than where export from a **Power Station** to the main **National Electricity Transmission System** is not dependent on a single transmission circuit.*

(additions shown in italics

ii) Inclusion of parallel HVDC circuits

3.31 The Original proposal puts forward solutions for the two main issues needing to be addressed in order to facilitate HVDC transmission circuits that parallel the AC network into the TNUoS charging model:

i) As set out above, the charging calculation uses a load flow to calculate incremental costs. Power flows on the existing AC network are dictated by the relative impedance of the individual network components (such as overhead lines and cables). These power flows are replicated in the load flow aspect of the tariff calculation. However, in the case of HVDC transmission circuits that parallel the AC transmission network, the power flow is controllable and not dictated solely by the impedance characteristic. Therefore, to include HVDC in the load flow aspect, assumptions need to be made on how much power will flow on the HVDC transmission circuits relative to the rest of the AC transmission network; and

ii) The calculation of the expansion factor (i.e. relative unit cost) for HVDC transmission circuits.

3.32 A high-level summary of the HVDC aspect of the Original proposal is set out in Table 8, below.

ii. HVDC Circuits – Including these circuit types into the methodology		
i)	Incremental power flow calculation	When calculating background power flows: - model HVDC transmission circuit as pseudo-AC circuit; - calculate HVDC transmission circuit flow by apportioning flows with parallel AC circuits, using relative circuit ratings; - average flows across all major transmission system boundaries crossed by the HVDC circuit; - set impedance of the HVDC transmission circuit to achieve this flow.
ii)	Expansion Factor (unit cost) calculation	When calculating expansion factors: - include both converter station costs and cable costs; - create a unique value for each HVDC transmission circuit.

Table 8 – Summary of the HVDC aspect of Original proposal

<u>i) Power Flow</u>

3.33 It is proposed that the treatment of power flow on an HVDC transmission circuit in the Transport Model be based on a simplifying assumption. This treatment can be made due to the controllable nature of these links relative to power flows on the parallel AC network, which are dictated solely by the impedance of a transmission circuit and that of the remaining network.

3.34 As a result, the Original proposal would model an HVDC transmission circuit as an AC circuit for the purposes of calculating the incremental power flow element of the locational signal. This approach requires the calculation of impedance for the equivalent AC transmission circuit (i.e. the circuit characteristic that dictates power flow) and is considered a reasonable simplification.

3.35 This Original proposal would calculate the impedance by adjusting the impedance of the HVDC transmission circuit in the load flow in order to achieve a pre-determined power flow through it in the base case. This power flow is determined as a proportion of the average circuit ratings of all the circuits comprising the main transmission boundaries that the HVDC circuit crosses (i.e. the main transmission routes that the circuit would parallel and therefore provide additional capacity across).

3.36 To achieve this, the ratings of all transmission circuits that cross each transmission boundary individually are summed, excluding the HVDC circuit itself. Subsequently, the power flow across each transmission boundary without any flow on the HVDC circuit would be used to produce a ratio of power flow to transmission boundary total circuit rating (accounting for the direction of the boundary flow in the base case).

3.37 These ratios can be used to calculate an average for all transmission boundaries that the HVDC transmission circuit crosses. This average power flow to total circuit rating figure is used to set the impedance of the AC equivalent HVDC circuit to produce the power flow that gives this ratio to the HVDC circuit rating.

ii) Expansion Factor

3.38 The TNUoS charging methodology incorporates the unit cost of various transmission technologies by calculating the cost of a given technology relative to the cost of 400kV overhead line. This allows for the calculation of a multiplier, known as an expansion factor, which is used in the Transport model to calculate the locational signal within TNUoS charges. As HVDC transmission technology does not currently exist in the Transport Model, a method of incorporating its unit cost is also required.

3.39 When using HVDC cables, as opposed to overhead lines, the unit cost of these are generally less than an AC equivalent. However, in order to utilise this technology relatively expensive power electronic switching devices and associated power quality equipment (e.g. reactive compensation devices), that convert the AC power signal to DC and back again, are required to interface with the existing transmission network. These devices are collectively known as HVDC converter stations. It is for this reason that HVDC circuits are generally only utilised for power transmission over long distances. As such, the Proposer believes that HVDC converter stations should form an integral element of the locational signal for these transmission circuit types, so that generators are better able to internalise the transmission network cost impacts of plant location and entry and exit decisions.

3.40 As the Original proposal considers HVDC converter stations as an integral element of the distance related locational signal of the HVDC transmission circuit, it is proposed to include the total cost of these converter stations, as well as the associated cables or overhead lines making up the circuit, into the expansion factor calculation for each HVDC transmission circuit. This approach is also consistent with that used in the calculation of TNUoS tariffs for offshore transmission networks. Whilst the charging calculation for offshore networks is different to that of onshore transmission infrastructure, these two approaches are currently, and should remain, consistent.

3.41 With the cost of converter stations included, each representing a large fixed cost on either end of the transmission circuit, it is necessary to calculate a unique expansion factor for each HVDC circuit on the transmission network in order to maintain cost reflectivity for circuits of varying length. The Proposer therefore believes that a specific expansion factor should be determined for each HVDC circuit.

iii) Inclusion of sub-sea island connections

3.42 In order to calculate cost reflective charges for this type of transmission circuit, the Original proposal primarily addresses how the expansion factor should be calculated for underground and sub-sea cable technologies not included in the charging methodology.

3.43 As outlined above, the charging methodology incorporates the unit cost of various transmission technologies by calculating the cost of a given technology relative to the cost of 400kV overhead line. This allows for the calculation of a multiplier, known as an expansion factor, which is used in the Transport Model to calculate the locational signal within the TNUoS tariff. As the AC and HVDC, sub-sea and underground technologies proposed for the Scottish island transmission connections do not currently exist in the Transport Model, a method of incorporating their unit cost is required.

3.44 A high-level summary of the islands aspect of the Original proposal is set out in Table 9 below.

iii. Island Connections – Including these circuit types into the methodology		
i)	Local / Wider definition	When classifying island nodes as part of the MITS: - utilise the updated definition (see 3.30); - take account of reduced security, where relevant.
ii)	Expansion Factor (unit cost) calculation	When calculating expansion factors: - create a specific expansion factor for each AC technology; - for HVDC connections maintain consistency with HVDC approach set out above.

Table 9 – Summary of islands aspect of Original proposal

3.45 For transmission spurs, such as those connecting the Scottish islands, the Original proposes to calculate new expansion factors for each type of circuit technology proposed. Where such circuits are comprised of HVDC technology, the methodology would be consistent with that outlined for HVDC above. As such, this approach would also be consistent with that used in the calculation of TNUoS tariffs for offshore transmission networks.

4 Summary of Workgroup Discussions on Sharing

Introduction

4.1 The transmission network capacity sharing aspect of the CMP213 Modification proposal seeks to improve the cost reflectivity of the Transmission Network Use of System (TNUoS) tariffs, by recognising transmission network capacity sharing by generators in the Investment Cost Related Pricing (ICRP) TNUoS calculation. Further details are provided in Annex 4.

4.2 The basic rationale of the charging methodology change arising from the CMP213 Original (referred to as "Original proposal") is due to amended transmission network planning assumptions. Historically, transmission network planning has assumed that increased generation on the system requires a commensurate amount of new transmission network capacity, whereas transmission planners are increasingly considering cost benefit analysis, implicit within which are assumptions regarding the extent to which Power Stations with differing characteristics share capacity on the transmission network. The Original proposal seeks to reflect this shift in the basis of transmission network planning assumptions in the TNUoS charging methodology.

Summary of Workgroup and consultation discussions to date

4.3 Section 4 of the report is intended as a high level summary of Workgroup discussions. Further details of the Workgroup debate prior to the Workgroup consultation can be found in Annex 4 and the Workgroup consultation responses can be found in Volume 3 of this report. Details of further Workgroup discussions after the Workgroup consultation can be found in this Section, referencing the pre-Workgroup consultation discussions and consultation responses received where applicable.

4.4 Prior to the Workgroup consultation, the Workgroup discussed both the Original proposal and a number of potential alternatives. As this aspect of the CUSC Modification proposal represents a significant change to the existing ICRP calculation, it is quite detailed in nature and despite its outward simplicity is based on underlying concepts that can be difficult to conceptualise for non-transmission experts. The Workgroup spent a considerable amount of time discussing, debating and challenging the Original proposal in order to fully understand it. Clarification of some of the more technical detail of the Original proposal can be found in Annex 8.

4.5 The Workgroup began their deliberations on the Original proposal, discussing the use of CBA and full market models in transmission planning and how these translated in to actual transmission investments. This was seen as key to understanding the Original, as market modelling was also used during the Workgroup as part of the assessment process to explore and develop the Original proposal. An overview of transmission planning using CBA can be found in the relevant Workgroup consultation section Annex 4, 4.14-4.27.

4.6 The Workgroup were asked, by the CUSC Panel, to report on the following specific issues as part of their Terms of Reference, which were in line with / in addition to those set out in the Authority's SCR Direction[5] (appropriate report paragraphs from Workgroup discussions referenced):

(a) whether intermittent generation should contribute to the peak element of the tariff (4.149-4.154);

[5] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20direction%2025%20May%202012.pdf

(b) whether load factor is an appropriate measure of the level of sharing (4.127-4.148);
(c) whether the proposed method for calculating load factor is an appropriate measure of forward looking charges (subject to item b) (4.127-4.148);
(d) whether to use maximum line flow when attributing circuit MWkm to the Peak Security and Year Round elements or an alternative approach (Annex 4, 4.348-4.354);
(e) whether shortening circuit MWkm may be an alternative to the use of load factor in reflecting sharing (4.82-4.92); and
(f) comparison of the modelled charging outputs to real network investment costs (Annex 15).

4.7 The Workgroup agreed the core areas to be considered for the sharing aspect of the Original proposal could be summarised as:

Considerations from the Direction	Potentials changes to Original	
a) How charging structures should be applied geographically; in particular where zones are dominated by one type of generation	i)	Account for diversity in a plant type specific manner for each zone
	ii)	Account for diversity in a zonal average manner for each zone
	iii)	Different treatment for positive and negative charging zones
b) Alternative approaches to ALF for reflecting User characteristics into charging	i)	TEC only
	ii)	SQSS based generic factor
	iii)	Other Generic load factor
	iv)	NGET and/or User forecast
	v)	Hybrid approach
	vi)	Alternatives measures (metered, FPNs)
	vii)	Ex-ante or ex-post
c) Whether intermittent technology types should be exposed to the peak element of the tariffs	i)	Exposed to some extent
	ii)	Indexed linked to something

Table 10 – Considerations from the Direction for sharing

4.8 In developing the Original and potential alternatives on sharing, some detailed analysis was undertaken by a subgroup of Workgroup members. Market models and concepts were considered on a more theoretical basis to ensure that results arising from analysis of market data could be corroborated with what would be expected to happen in theory. This approach also helped all members of the Workgroup to better understand the concepts behind the CMP213 Original proposal and potential alternatives by breaking it down into its component parts. The results of the subgroup modelling were considered in context by the Workgroup, noting that a market model is based on certain assumed behaviours and input assumptions.

Areas for development of CMP213 Original Proposal and Potential Alternatives

4.9 The Workgroup discussed further areas where the Original proposal could be developed, in addition to those highlighted by the Authority's Direction and where potential alternatives could be developed. These are described further in Annex 4 and are listed in Table 11below.

Potential Alternatives	
i.	Sharing applies to local
ii.	Method of allocation of MWkm to YR and PS backgrounds
iii.	Don't have a dual-background (YR only)
iv.	Use of a full market model to calculate charges (more than 2 backgrounds)
v.	Background scaling different to GSR-009
vi.	Anticipatory application of sharing (or wider)
vii.	Explicit sharing
viii.	Incorporating circuit loading (e.g. LRIC) into methodology
ix.	Application of load factor (or variant) to residual as well as year round
x.	A method to recover more revenue through the locational element of tariffs
xi.	Alternative zoning methodology

Table 11– Potential Alternatives for sharing

4.10 In this section, each of the three main considerations from the Authority's SCR Direction (set out in Table 10, above) are taken in turn, with each of the potential changes to the CMP213 Original proposal covered under these main considerations. The potential alternatives outside this framework are also considered. Finally, a summary of potential alternative elements carried forward into potential WACMs are presented (see 4.164).

Discussion and potential alternatives

a) How charging structures should be applied geographically; in particular where areas are dominated by one type of generation

4.11 The use of each generator's Annual Load Factor (ALF) as a surrogate for the incremental cost of transmission network investment (driven by constraint cost) is at the heart of the Original proposal. The Proposer believed a generator's ALF, as a manifestation of many underlying variables, was a simplification of the relationship between each generation plant type and incremental transmission cost triggered. The Proposer also believed that ALF produced a better relationship with investment costs than the use of generation capacity (TEC) alone, and represented the appropriate balance between simplicity and cost reflectivity in the TNUoS tariff calculation.

4.12 Much work was undertaken prior to the Workgroup consultation within the Workgroup to explore the ALF versus incremental constraint cost relationship. As the relationship between ALF and incremental constraint costs is such a key part of the Original proposal, this was also re-explored after the Workgroup consultation.

4.13 In order to explore the relationship prior to the Workgroup consultation (Annex 4: section 4.41-4.56), the Proposer undertook a significant amount of market modelling using the National Grid Electricity Scenario Illustrator (ELSI)[6] model, making a range of assumptions about background conditions, in search of a method for taking into account the many characteristics of each specific generator in relation to its incremental transmission network requirements. Outputs from this modelling are shown in Annex 9, and examples are shown below in Figure 4.

[6] http://www.talkingnetworkstx.com/consultation-and-engagement.aspx

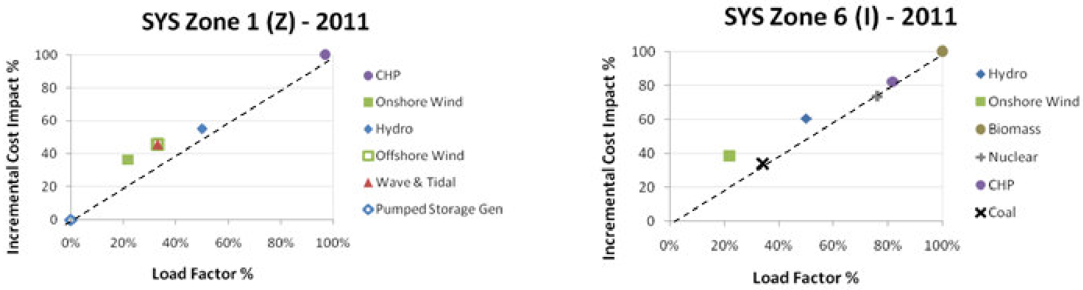

Figure 4 – Example ELSI analysis

4.14 From this ELSI based analysis the Proposer believed that a simple proxy for each generator's incremental impact on transmission network costs existed in the form of its ALF, and that this proxy could be incorporated into the existing ICRP approach in order to improve the cost reflectivity of this approach. The Proposer suggested this was because ALF is a manifestation of many individual generation plant characteristics, reflecting its overall market driven operation. The Original proposal explicitly avoided requiring these detailed individual characteristics in the derivation of charges; i.e. ALF is used as a simple proxy.

4.15 The Proposer acknowledged that there are imperfections in the relationship but that in their view it was still more cost-reflective to charge on a generator's actual ALF than charging on generation capacity (TEC) alone, which assumes – in effect – an ALF of 100%, and remains relatively simple.

4.16 Prior to the Workgroup consultation, analysis was undertaken in two separate market models to test the relationship between a generator's ALF and incremental constraint costs. It became clear that this relationship deteriorates in areas on the extremities of the transmission 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 has expensive bid prices (the cost to remove them from the system when transmission network capacity is restricted). However, given the uncertainty of when future generation will connect, it was difficult for the Workgroup to establish when the deterioration would become significant. Some Workgroup members believed that the relationship does not hold from the outset, regardless of background conditions.

4.17 The Proposer believed that the simplicity of an ALF based approach potentially outweighs any potential cost reflectivity benefits that a more complex approach, taking account of generation plant diversity, could bring.

4.18 The cause for divergence in the relationship was discussed further following the Workgroup consultation. As part of this discussion, the variables affecting incremental constraint costs were revisited (full discussion prior to Workgroup consultation in Annex 4, 4.66-4.101)

4.19 The Workgroup agreed that annual incremental constraint costs for each generator with a given TEC (i.e. £/MW/annum) are comprised of two main components, illustrated below in Figure 5 which could be further sub-divided into five variables.

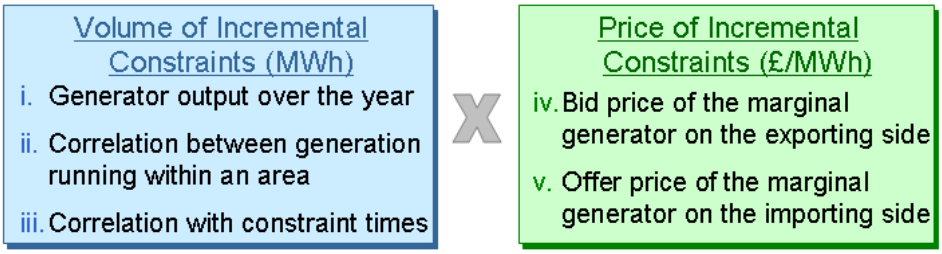

Figure 5 – Components that drive transmission constraint costs

4.20 The effect of these elements (in terms of whether they have an upward or downward effect) on the total incremental costs of constraints is shown below in Figure 6. Some elements such as generator output over the year, the coincidence of running at time of constraint and the impact of bid/offer prices all lead to higher total incremental constraint costs as they increase. Conversely, if there is decreased correlation between generation running in an area of the transmission network (non-coincident running), this lessens the overall impact on incremental constraint costs.

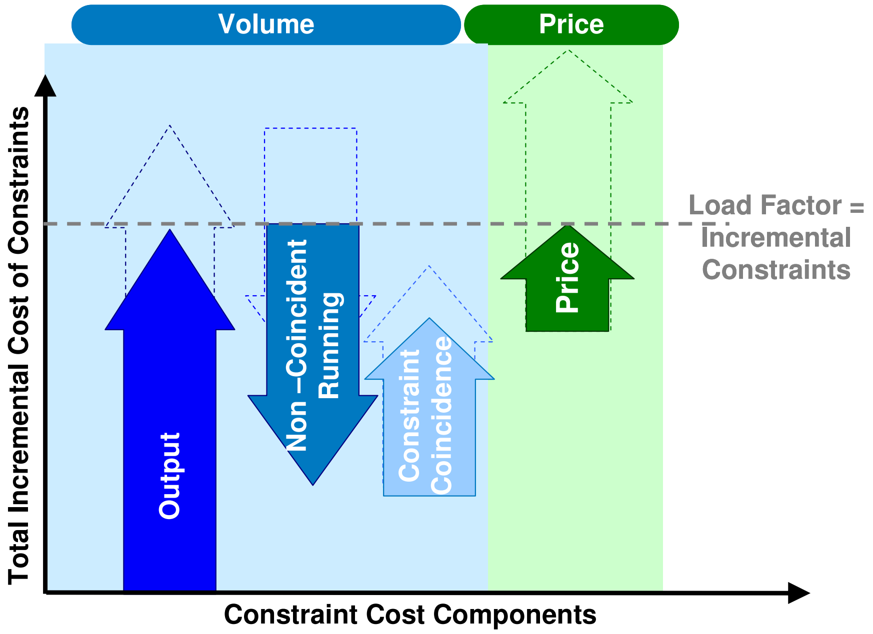

Figure 6 - Price and Volume constraint cost drivers

4.21 For export constrained transmission charging zones, the Proposer hypothesised that the main cause of divergence was down to the effect of high generator bid prices in areas of the system dominated by low carbon plant. This is because in terms of bid prices, low carbon plant is more expensive to bid off than carbon plant, which generally has a lower bid price (close to marginal bid price), and is cheaper to constrain off. The higher bid price of the majority of low carbon plant is in part a feature of these types of generation which either 'must run' when the fuel source is available or for technical reasons, and also a result of support programmes such as the Renewables Obligation, which affect their bid price.

4.22 The linear relationship between load factor and incremental constraint costs breaks down when bids cannot be taken from plant at close to wholesale marginal price, and are taken from low-carbon plant instead. This is demonstrated in Figure 7 below.

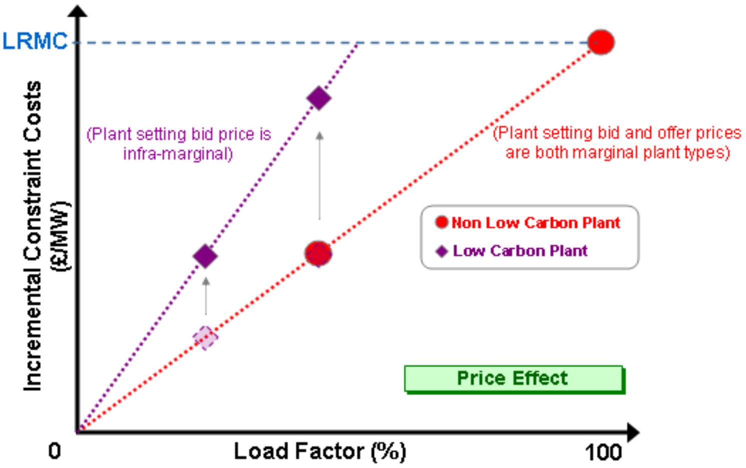

Figure 7 – Divergence in the linear relationship between low carbon and non low carbon plant

4.23 One method that was considered (although not taken further) was to add a load factor multiple in areas of the transmission system with low plant diversity. This is relationship is demonstrated in the Figure 7 above. This multiple would increase the effective load factor for plant with negative (high cost) bid prices and reduce the effective load factor for positive (low cost) bid prices. Whilst this initially seemed an attractive method, it became clear that determining the bid price to use would be challenging and potentially extend the proposal into broader commercial arrangements. Actual offered bid price (as opposed to accepted bid prices) in some circumstances reflect other aspects of market operation. Use of the fundamental energy cost (based on Renewable Obligation Certificate (ROC) banding and carbon energy prices) would also lead to additional complexity, as this could potentially lead to different multiples for different plant depending on the actual ROCs received. Whilst a bid price multiple could have been considered further, the options that adjusted the TNUoS charge based on the level of diversity were considered more promising avenues for development by the Workgroup.

4.24 For import constrained transmission charging zones, the Proposer rationalised that whilst a similar comparison could be made with the spreads of offers, the relationship could be more complex due to the effect of demand side management options, which are limited or theoretically very expensive where demand is assumed to be met at any cost.

4.25 An example was given to demonstrate the bid/offer price impacts on constraint cost issue using two example areas connected by a transmission system, as shown diagrammatically below.

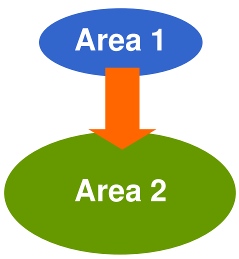

Figure 8 – Two example areas

4.26 Area 1 is an exporting zone with limited market participants, and less carbon plant. Area 2 is an importing zone with more market participants, and more carbon plant. The relative bid and offer prices of each area are shown below in Figure 9.

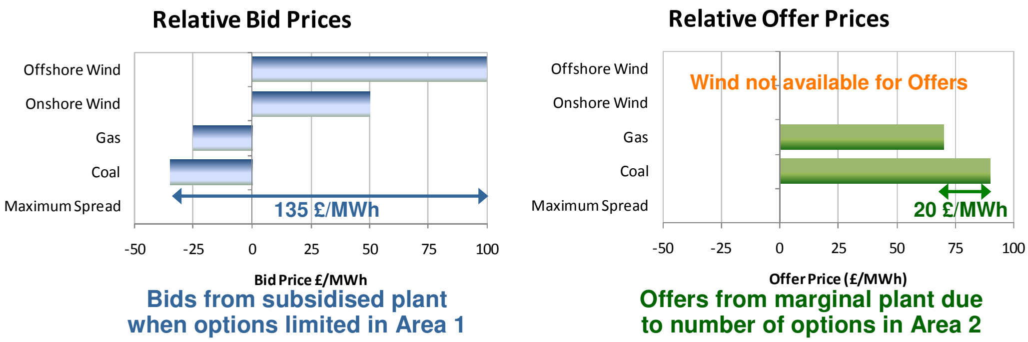

Figure 9 - Relative bid and offer prices for example areas 1 & 2

4.27 It can be observed that bid prices have a much higher spread between carbon generation technologies, with bid prices close to the marginal price, than low carbon generation technologies where bid prices are significantly higher. As low carbon sources are not generally available to call on for offers, as they will generate whenever their fuel source is available, the offer spread is much smaller.

4.28 Hence, the Proposer drew the conclusion that the effect of bids was much higher, in terms of impacting on the ALF vs. transmission costs relationship, than offers.

4.29 This example shows how in export constrained zones bid prices may become a significant factor in incremental constraint costs. The upward effect of high bid price is shown diagrammatically in Figure 10 below.

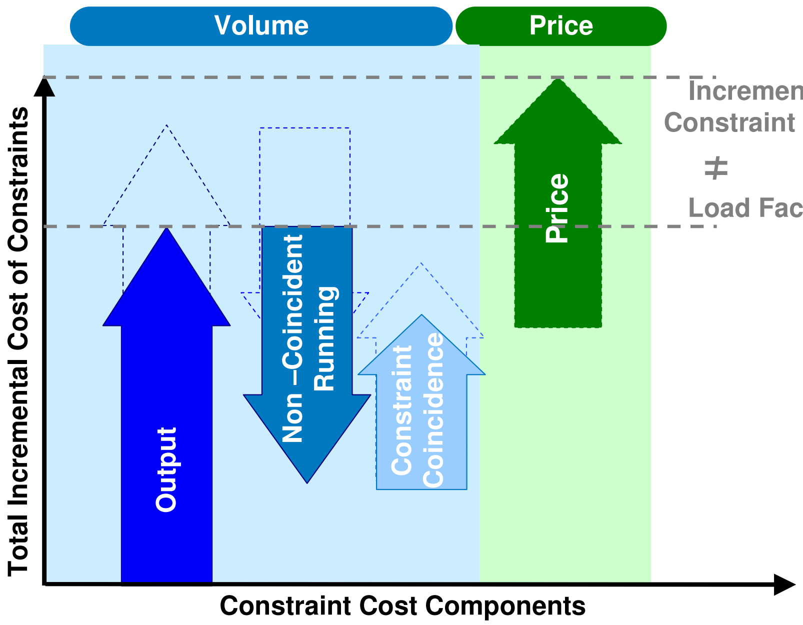

Figure 10 – Upward effect of high bid prices

4.30 Results of the analysis by a modelling subgroup of the Workgroup corroborated the Proposer's hypothesis. This was presented to the Workgroup and provided some insight into the interactions between bid and offer prices, ALFs and transmission boundary limitations.

4.31 Hence, the Workgroup generally accepted that there was potential to improve the accuracy of the relationship between ALF and the incremental cost of transmission, and that this could be reflected through consideration of the effect of bid/offer prices for different generation technologies.

4.32 The term ‘diversity’ was developed by the modelling subgroup to describe the relative volumes of high bid price, low carbon plant using an area of the transmission system compared to the volumes of low bid price carbon plant. It was postulated that diversity could be represented in a zone by categorising plant into "carbon" and "low carbon", and the relative proportion of each would help to quantify the general level of diversity behind a transmission boundary.

4.33 The "low carbon" plant category was defined (for the purposes of CMP213) as containing generation plant that is “must run” and always generates when fuel is available or, for technical reasons is inflexible, irrespective of transmission system need; e.g. demand level. A further characteristic of this type of generation plant is relatively costly (high negative) bid prices. In the case of renewable plant, this results in the need for the generation plant to be paid to reduce output as fuel is in general low cost or subsidised (ROC or proposed Contracts for Difference (CfD) based) and reduced output results in loss of income for the generator. In the case of existing nuclear plant, flexibility is technically infeasible; however this may not be the case for future nuclear builds where output-based CfD subsidies are expected.

4.34 The "carbon" category was defined (for the purposes of CMP213) as containing generation plant that is flexible in nature and can reduce/increase output driven by market price and transmission system needs. The principal further characteristic of this generation plant type is that in general it will pay a proportion of its avoided fuel cost, when bid down, to the System Operator, so offering a low cost solution to reducing constraints, providing it is running.

4.35 Categorisations of plant into “carbon” and “low carbon” for the practical application of diversity methods can be found in 4.53.

4.36 It was further postulated by the modelling subgroup that the ideal network scenario is to build transmission network such that the low carbon plant is rarely constrained off, and a network of this size could absorb an equal volume of carbon plant. In such an idealised transmission network, constraint action would only be required on carbon plant and this can be accessed at relatively low cost. In any event, for significantly expensive actions (negative bid price) the general assumption is that, in areas where this type of plant is dominant, TOs would build transmission network capacity at or very close to the total generation capacity in the area concerned. Likewise, where the costs of constraining plant off was relatively low, the general assumption is that the transmission network capacity would not be very close to the total generation capacity in the area concerned and this would, therefore, mean lower transmission network investment.

4.37 Two areas of further work by the modelling subgroup considered this relationship. The first was based on a two nodal transmission network as shown below. The combined total capacity of generators A and B was maintained at 500MW and the proportion of low carbon (wind – generator A) and carbon generation (thermal plant with a high load factor – generator B) was varied to establish how the constraint cost varied relative to the percentage of low carbon plant normalised to pure load factor relationship.

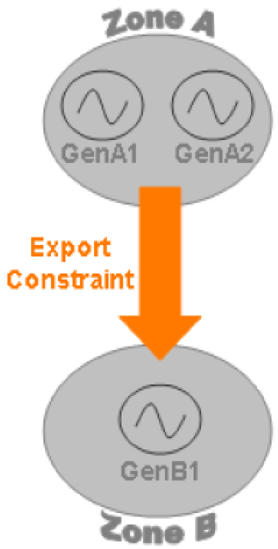

Figure 11 – Two nodal transmission network example

4.38 As we see in Figure 7, where bid and offer prices are taken from marginal plant types, there is a linear relationship between load factor and incremental constraint costs. The impact of different categories of plant on this relationship is explored in Figure 12 below. The red dotted line shows the ideal linear relationship. Mapped against this are the impact of low carbon and carbon generation on this relationship as the percentage of low carbon generation in a zone increases. As the percentage of low carbon plant increases above 50% the cost of bids significantly increases. It follows in these circumstances that incremental low carbon plant increases constraint costs whilst incremental carbon plant reduces incremental constraint costs. This latter effect is because the volume of low carbon plant that runs provides cheaper bids than previously available in that transmission charging zone; i.e. the slope in that zone was previously steeper.

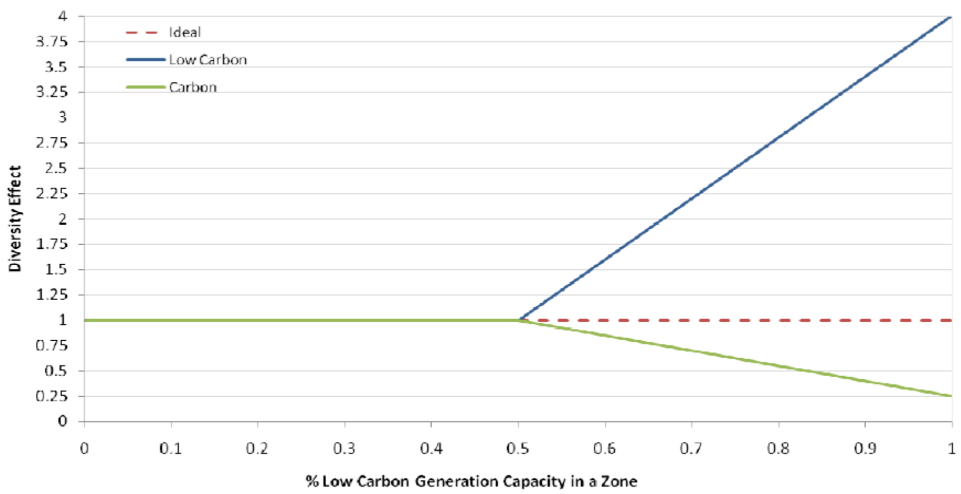

Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

4.39 Other analysis undertaken by the modelling subgroup considered an illustrative 2012 scenario and, whilst keeping the volume of GB generation constant, moved the low carbon plant south of the B7 transmission boundary until the volume of low carbon plant north of B7 was 10%. Generation was then moved north of B7 to test the load incremental cost relationship. Figure

13 below shows the incremental constraint cost. For volumes of low carbon plant below 10%, the relationship to load factor was weak as only a few scenarios resulted in constraint action being required. Between 20-35% of low carbon plant behind a boundary, the load factor relationship was linear. Above 35% the relationship deteriorated such that at 50% low carbon plant behind a boundary, the low carbon volume needed to be multiplied by 2 to have the same effect as carbon plant.

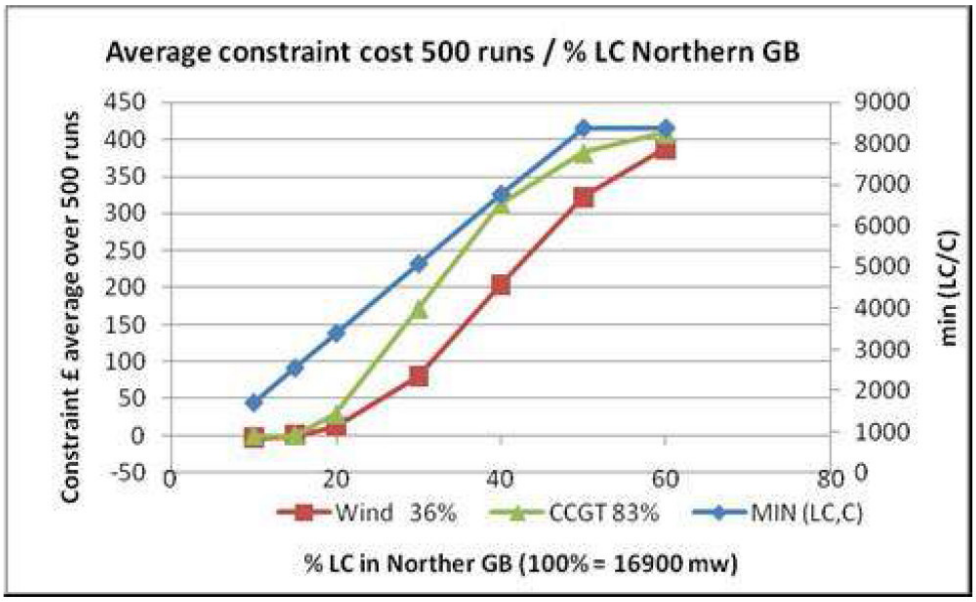

Figure 13 – Average constraint cost 500 runs / % LC Northern GB

4.40 A Workgroup member further argued that the relationship between carbon and low carbon plant is most complementary (where the lowest constraint cost is achieved) when there are equal volumes of each generation plant type (low carbon / carbon) behind a boundary.

4.41 These two areas of work demonstrated that there is potentially a generator load factor relationship that allows the sharing of the transmission network between carbon and low carbon plant. This relationship is linear with load factor until 50% of generation behind a transmission boundary is dominated by either low carbon plant or carbon plant, after this a load factor multiple (a diversity factor) needs to be applied to both classes of generation plant to represent the incremental constraint cost. This then serves to reduce the impact of load factor as a direct proxy for sharing. It was noted that the situation may be different for importing zones for the reasons stated in 4.24.

4.42 This analysis on export constrained zones led to the development of several candidate alternative charging methodologies that had the potential to reflect some or all of these interactions. These are explained below.

4.43 All these methods required development of a methodology to establish suitable transmission boundaries between generation charging zones. The Proposer put forward that this would be through the representation of the transmission system as a connectivity diagram linking generation charging zones. The zonal incremental MWkm would be used as the measure of the 'thickness' of a boundary by considering the difference between one boundary's incremental MWkm and that of the next boundary towards the null point on the system. An illustrative connectivity diagram for 2012/13 generation charging zones is provided in Figure 14 below. Illustrative examples on calculating boundary incremental MWkm, and their consideration in low carbon / carbon sharing, is provided in the draft legal text for each of the diversity alternatives, and can be found in Volume 4.

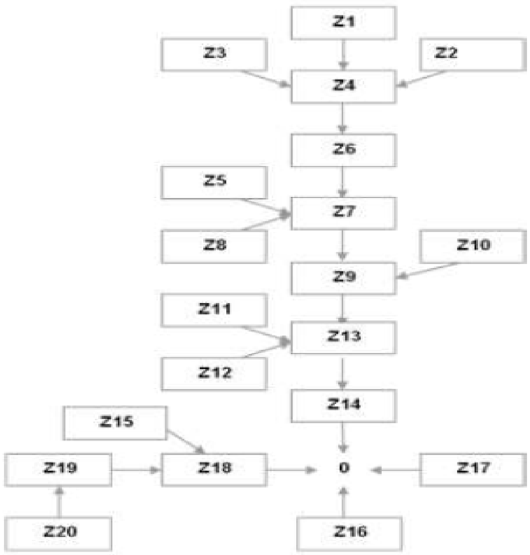

Figure 14 – Illustrative connectivity diagram for GB system based on 2012/13 charging zones

4.44 The Proposer put forward the following criteria for the establishment of the charging zone connectivity. Firstly, that connectivity should be based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport Model. Secondly, that the connectivity should be reviewed by National Grid at the start of a new price control period, and under exceptional circumstances, such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing connectivity and in line with the notification process set out in the Transmission Licence and CUSC.

4.45 A Workgroup member noted that from 2013/14 there will be 27 TNUoS generation charging zone (compared to the 20 zones for 2012/13 shown in Figure 14). As a result there will be a number of parallel paths to consider in the connectivity diagram and questioned how this would be resolved.

4.46 The Proposer noted there were two parallel considerations. Firstly, that of two TNUoS generation charging zones in parallel, and the second of parallel paths between TNUoS generation charging zones.

4.47 It was proposed that cases of two TNUoS generation charging zones in parallel would be resolved through amalgamation of those two zones, with the lower of the incremental MWkm for the boundaries above those zones to be used. This would give maximum consideration to zonal sharing. This is illustrated in Figure 15 below.

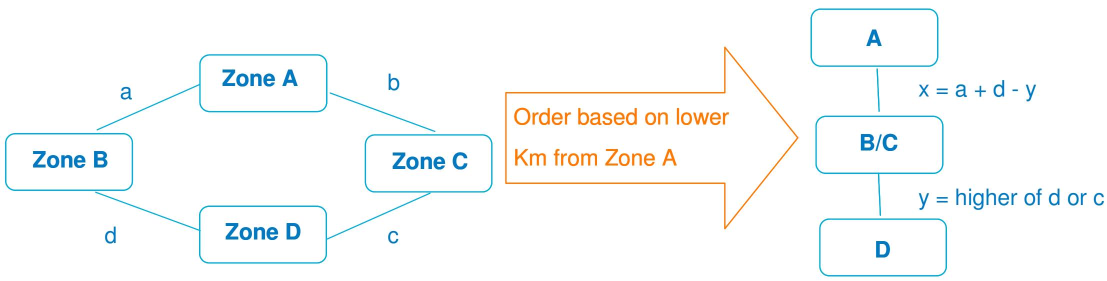

Figure 15 –Illustrative treatment of parallel zones

4.48 For parallel paths, the Proposer described that the connectivity would be 'reduced' to a single path using the longest parallel path MWkm. This is illustrated in Figure 16 below.

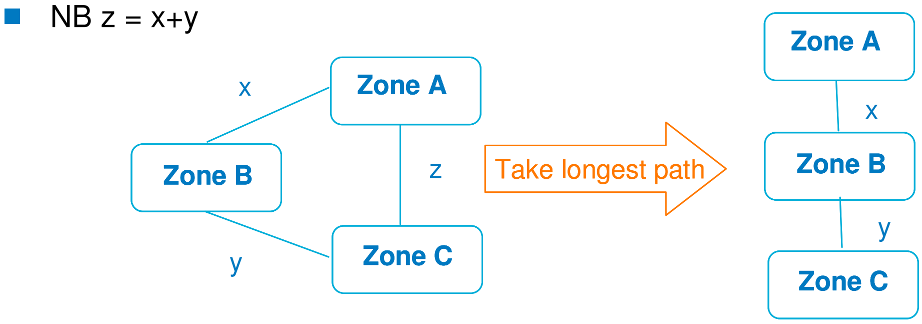

Figure 16 – Illustrative treatment of parallel paths

Methods for addressing diversity

4.49 The Workgroup discussed the possibilities for addressing the diversity issue within the TNUoS charging methodology. In doing so, three possible methods were devised, following the work of the modelling subgroup, which are summarised in Table 12, below.

Area	Original	Method 1	Method 2	Method 3
Dual background	Yes	Yes	Yes	No
How sharing is applied	Sharing on Year Round background only	Sharing on Year Round background only	Sharing on Year Round background only	Sharing applied to all (only Year Round background)
Wider locational tariff components	2 (Year Round & Peak Security)	3 (Year Round shared, Year Round non-shared, Peak Security)	3 (Year Round shared, Year Round non-shared, Peak Security)	1 (Year Round)
Sharing method	Load factor on all MWkm	Load factor on shared MWkm, capacity on not-shared, effective max sharing 100%	Load factor on shared, capacity on not-shared, effective max sharing 50%	Effective MWkm = not shared/total; i.e. 10% shared ➔charging is on 90% effective, max sharing 50%.
MITS sharing	All Year Round incremental costs	Year Round split into shared / not shared	Year Round split into shared / not shared	All incremental costs with zonal sharing factors
Application of generator specific sharing factor	Yes	Yes; to shared element	Yes; to shared element	No

Area	Original	Method 1	Method 2	Method 3
Diversity calculation	None	Based on deterministic relationship between low carbon / carbon ratio. All MWkm shared at 0% to 50%; sharing reduces from 50% to 100% low carbon.	Based on minimum of low carbon / carbon generation behind a boundary	Based on minimum of low carbon / carbon generation behind a boundary
Method for split of Incremental Costs	None	Zonal boundary length using transmission boundaries of influence	Zonal boundary length using transmission boundaries of influence	Zonal boundary length using transmission boundaries of influence

Table 12 – Options considered for addressing generation plant type diversity issues

4.50 Alternate methods were considered where ALF was multiplied for low carbon plant where there was low diversity (as discussed in 4.23) but on balance the Workgroup believed that methods 1 and 2 achieved a similar effect.

4.51 These methods were presented during the Workgroup consultation, and a number of consultation respondents highlighted that these methods should be developed further, including on a local basis. The Workgroup believes that local sharing has been considered through the development of the proposed Counter Correlation Factor (CCF) (see section 4.105-4.113) which would apply to all radial transmission circuits, including those deemed local. Analysis by National Grid indicated that in addition to the radial transmission circuits to the Scottish islands, that there was only currently one other part of the MITS where this situation would arise, namely the radial circuit from Fort Augustus through Fort William, Broadford and Ardmore.

4.52 Prior to the Workgroup consultation, the Workgroup noted that further consideration was required with respect to which generation plant types are included / excluded from the low carbon and carbon definitions that were proposed to be used, and that this could result in a variation to any of the methods for addressing diversity developed by the Workgroup. This classification is a simplified way of catergorising plant by likely bid price characteristics.

4.53 Following the Workgroup consultation, the supporter of Method 1 confirmed that the classifications in Table 13 below would be used for carbon vs. low carbon definitions, and that this had also been used in the analysis used to investigate diversity options. There was a majority Workgroup view that this classification was adequate and that this option would be used for other potential diversity alternatives.

Carbon	Low Carbon
Coal	Wind
Gas	Hydro (excl. pumped storage)
Biomass	Nuclear
Oil	Marine
Pumped Storage	Tidal
Interconnectors	

Table 13 – Classifications used for carbon vs. low carbon

4.54 A member of the Workgroup noted that whilst this may well be the case generally there were at least two types of low carbon generation - biomass and hydro - where these classifications were inadequate. This workgroup member cited historic bid price analysis information presented to the workgroup (see Figure 17) as supporting evidence for this view, claiming that it justified hydro as carbon. There was little support for this approach in the Workgroup, with some Workgroup members disputing the overall argument presented. Other Workgroup members expressed the view that hydro would generally be a negative price, and that this was backed up in the majority of cases with evidence of Balancing Mechanism submissions, noting that this was not true in all cases. The majority of that Workgroup believed any diversity proposals should be based on theoretical assumptions or general data rather than linked to an individual generator's bid price submissions, and that the classifications were adequate for the purposes of these diversity options.

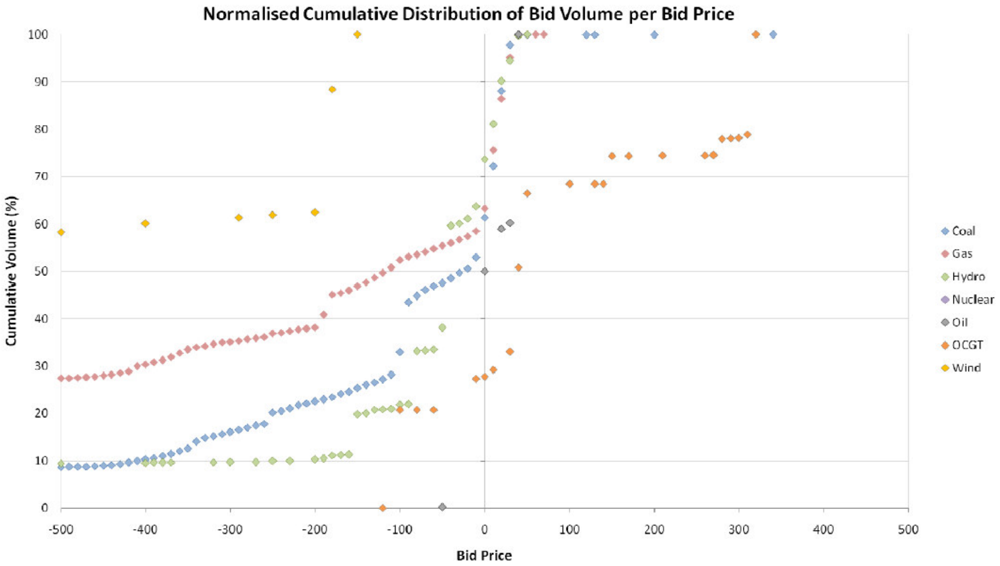

Figure 17 – Normalised Cumulative Distribution of Bid Volume per Bid Price

4.55 The classification into carbon/low carbon of the recently proposed linkage[7] between the GB electricity market and specific renewable generation assets located in Eire was raised in the Workgroup. It was confirmed that, as the regulatory arrangements for how this generation / connection would be dealt with was still unclear, it was not possible to provide a definitive classification (for this generation / connection) at this time. However, if such a link was made it seems likely the generation would also be classified (in CMP213 diversity terms) on a bid price approach, and may be likely to fall into the low carbon category.

4.56 It was also noted that carbon/low carbon classifications may need to be revisited after the UK Government's Electricity Market Reform (EMR) process has concluded, as this may affect the bid price of generation plant substantially.

4.57 Some Workgroup members challenged the assumption that sharing was only assumed to take place between plant groups (carbon/low carbon) in the diversity options, on the basis that they believed low carbon plant share. A Workgroup member believed this was not fully evidenced on the basis of how counter-correlation is modelled in ELSI (where counter-correlation is only modelled on a larger scale, between wind in 4 places in GB – 3 in England/Wales and Offshore and 1 for the whole of Scotland and used in ELSI, but not within zones). This Workgroup member argued that large and topographically diverse zones may well experience a degree of counter-

[7] https://www.gov.uk/government/news/energy-trading-creates-opportunities-for-ireland-uk-davey-rabbitte

correlation, and that in any event the basis of CCF (4.105-4.113) should have an opportunity to be reflected in the wider network.

4.58 Counter to this, the Proposer did not believe that the assumptions made limited the outputs of the model, as ELSI was used by transmission network planners, and therefore was fully representative of the decisions and analysis made in the design of the National Electricity Transmission System. It was suggested that if additional evidence was available to assist future development of the National Electricity Transmission System it should be submitted to SQSS Review Panel for consideration.

4.59 In developing the diversity alternatives, the Workgroup was aware of the need to avoid complexity where possible, but also being mindful that the results of simplification would be to potentially deliver a solution that was less cost reflective. On balance a simplified approach was adopted as this would give the possibility of further incremental change to address specific issues in the future. The areas where further development might occur were noted as:

- Counter correlation factors within diversity groups (carbon and low carbon groups);
- Further refinement of specific plant types in individual categories;
- Bid price multiple incorporated into a pure load factor option; and
- Addition of a flexible plant category such that high load factor inflexible plant would not benefit from reduced charges driven by diversity (most relevant to diversity 3).

4.60 The various diversity options proposed were developed with the background that they could be further incrementally changed with increasing complexity relative to the initial methodology.

4.61 The Workgroup considered that Methods 1-3 in Table 12 above should be taken forward as potential alternatives.

4.62 To aid Workgroup discussions, for each of the three candidate diversity potential alternatives (Methods 1 to 3) illustrative generator TNUoS tariffs were developed to help validate the charging methodology and better understand the key facets of each.

4.63 The detailed technical descriptions for the Original are contained in Annex 8 and the three potential alternatives for diversity are contained in Annex 4, 4.136-4.150. Illustrative tariffs for all these potential alternatives can be found in Annex 15. Illustrative examples of the three potential alternatives can also be found in the draft legal text in Volume 4. The following short descriptions of each potential alternative seek to draw out the key attributes.

Method 1 – Year Round shared/not shared split based on low carbon/carbon generation ratio

4.64 Under this potential alternative, sharing occurs until the volume of low carbon generation exceeds 50% behind a transmission boundary. Beyond this the sharing benefit is gradually reduced. This approach is set out in full in Annex 4 and results in a four part wider TNUoS tariff using Annual Load Factor (ALF) as follows:

$$\mathbf{(PS \times TEC) + (YR_{not\ shared} \times TEC) + (YR_{shared} \times ALF \times TEC) +}$$

$$\mathbf{(Residual \times TEC)}$$

Where; $YR_{not\ shared}$ and YR_{shared} are calculated using the pre-defined range of low carbon and carbon generation capacity ratios behind every transmission boundary, transmission boundary lengths and the transmission boundaries of influence as described in Annex 4, 4.136-4.142.

4.65 Under this Method, intermittent generation plant are not exposed to the Peak Security element on the basis that they are not modelled in this background for transmission network planning, but do contribute to the non-shared (capacity) element inherent in Year Round.

4.66 This Method is shown diagrammatically below in Figure 18.

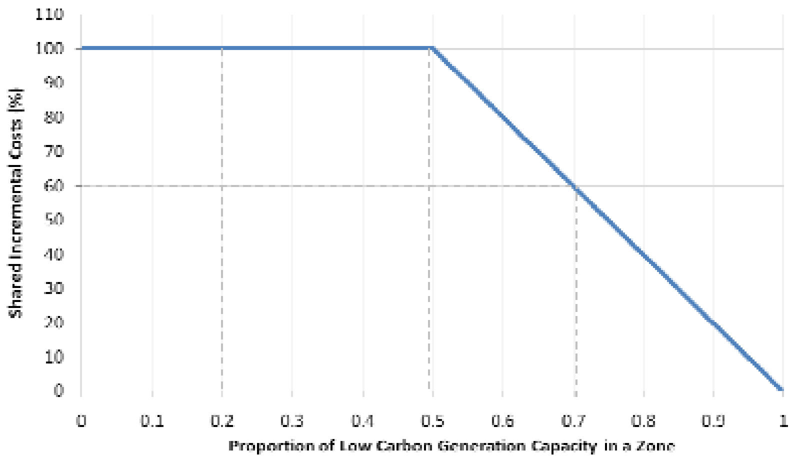

Figure 18– Diagrammatical summary of Method 1

4.67 The diversity Method 1 potential alternative was developed further following the Workgroup consultation, based on the analysis presented in 4.37-4.42.

4.68 Some Workgroup members felt that this Method was potentially more cost reflective than the Original. This is because the sharing element is applied based on an individual generator's ALF, whilst also reflecting the cost of low diversity behind a boundary linked to large negative bid prices. These members therefore believed that this potential alternative better recognises a generator's individual impact on expected transmission investment.

4.69 There was also concern from some Workgroup members that the Method did not deal well with negative transmission charging zones due to the added complexities associated with demand side management options. The Proposer also noted that offers have a much lower spread than bids (as in section 4.28).

4.70 Some Workgroup members also felt 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. For example, if you have a zone with large amounts of low carbon generation, and a carbon generator connects, there may still be minimal sharing deemed to take place, and therefore the carbon generator's TNUoS charge will be based predominately on capacity, even though the carbon generator is sharing 100% with low carbon generation.

4.71 Other Workgroup members felt the Method 1 diversity alternative would also increase volatility in TNUoS tariffs. This is because the amount of sharing is adjusted when new generation becomes part of the transmission network behind a boundary. This means that third party decisions on where to site their generation plant would affect the level of sharing behind that boundary. For example, if a greater amount of low carbon generation entered the area and pushed low carbon over the 50% point, sharing would be further reduced in line with the percentage reduction. These Workgroup members argued that this would make it difficult for Users (especially smaller parties) to predict their TNUoS charges over the medium term (leading to market uncertainty). Others argued that as diversity is considered on a boundary level, that new generation would have a much less significant impact on an individual User's TNUoS tariffs, as for the majority of the transmission system, carbon / low carbon sharing would be considered across multiple charging zones.

4.72 Some Workgroup members argued that this Method was not favourable as it treats Users differently in different parts of the transmission system on the basis of the calculation of their charges (from capacity to commodity). For example in areas with significant low carbon generation deployment, the majority of MWkm are charged on a capacity (TEC) basis whereas in areas with significant carbon generation deployment the majority of MWkm are charged on a pseudo-commodity basis based on ALF. Supporters of Method 1 largely agreed that this was the effect, but that it was a better reflection of how the system would be planned and so was more cost reflective overall. They noted the analysis performed on areas with little diversity / expensive bids demonstrated that intra zonal investments would be based more on generation capacity rather than generation load factor.

4.73 In addition, some Workgroup members argued that the use of the ALF scaling factor in Method 1 would introduce a new variable cost of generation element, which will need to be incorporated into a generator's short run marginal cost (SRMC). This will affect short run pricing decisions in the wholesale market. The calculation of ALF, which creates a lagging effect on an individual ALF scaling factor, makes accurately pricing this variable cost very complicated. They argued that this is likely to impact on the efficiency of the wholesale power market

Method 2 – Year Round shared/not shared split based on percentage minimum of low carbon or carbon generation to total

4.74 Under this Method, maximum sharing (50%) occurs when there are equal proportions of low carbon and carbon plant (0.5*ALF*tariff) behind a boundary. With either more or less carbon (or low carbon) sharing reduces. The benefit is specific to an individual generator based on its own ALF. This approach is set out in full in Annex 4 and results in a four part wider TNUoS tariff using ALF as follows:

$$\mathbf{(PS \times TEC) + (YR_{not\ shared} \times TEC) + (YR_{shared} \times ALF \times TEC) + (Residual \times TEC)}$$

4.75 Intermittent generation plant are not exposed to the Peak Security element on the basis that they are not modelled in this background for transmission network planning, but do contribute to the capacity element within Year Round. This Method is summarised in the diagram below in Figure 19.

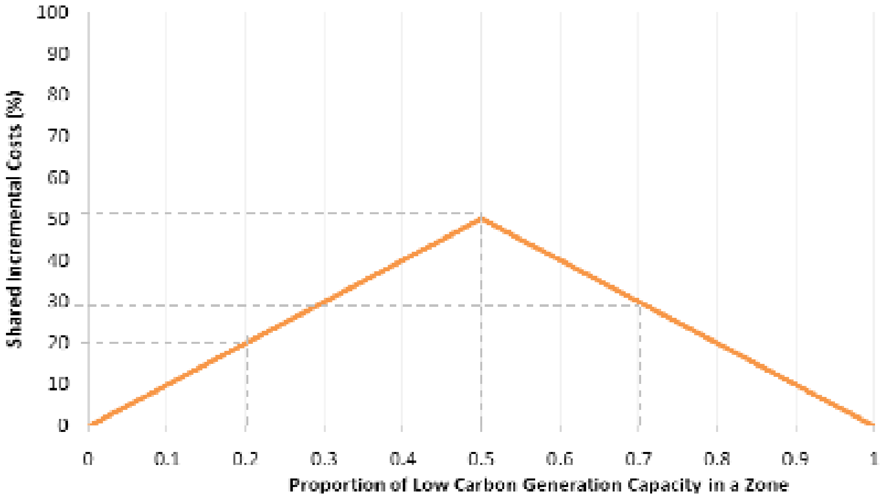

Figure 19 – Diagrammatical summary of Method 2

4.76 This potential alternative was developed further following the Workgroup consultation, based on the analysis presented in 4.37-4.42.

4.77 Some Workgroup members felt that this potential alternative was more cost reflective than the Original. This is because it assumes fewer MWkm are shared. Others felt that this feature made it less cost reflective. It was also argued that there were fewer issues of unequal treatment between generators compared to Method 1. This is because carbon and low carbon plant are prorated on an equal basis; i.e increasing proportions of carbon plant reduce shared MWkm in the same way that increasing proportions of low carbon plant do. In transmission charging zones with significant carbon or low carbon generation, plant only non-shared km are charged at TEC.

4.78 Other Workgroup members were unsupportive of this potential alternative on the basis that they believed that it introduced further complexity into the charging methodology, would potentially treat certain generation plant types differently and relied on bid prices which are not a good measure of transmission build. Some Workgroup members believed that this Method might address some of the simplifications relating to negative transmission charging zones associated with Method 1, as it allocates a greater proportion of charges based on capacity. Some other Workgroup members believed more complex solutions may be a better option (see 4.95).

4.79 One Workgroup consultation respondent argued that the 50% maximum sharing element of this potential alternative should be removed, on the basis that two generators could share full capacity if they do not run at the same time. An alternative view was presented that the 50% sharing cap was only theoretical with two perfectly counter correlated plants, and in reality could be lower. Some other Workgroup members questioned the validity of the cap on sharing of 50% of MWkm in any charging zone.

4.80 In addition, as previously discussed for Method 1, Method 2 would also continue to employ the ALF scaling factor. It was argued that this is likely to impact on the efficiency of the wholesale power market for the reasons provided above (see 4.73).

4.81 Other Workgroup members felt that, as argued in Method 1 above (4.71), for Method 2 this potential alternative could also increase volatility in TNUoS tariffs. Others argued that as diversity is considered on a boundary level, that new generation would have a much less significant impact on an individual User's tariffs, as for the majority of the system carbon / low carbon sharing would be considered across multiple charging zones.

Method 3 – Single background shared/not shared split based on percentage minimum of low carbon or carbon generation to total

4.82 The "pilot" version of diversity 3 included a load factor test such that the benefits of diversity would only reward plant that could be flexible and had load factors in a range of 15% to 75%. Equal benefit was available for all within this range. This was based on the premise that diversity could not be allocated based on individual load factor, as it was the combination of plant within an area that reduces constraint costs. High load factor thermal plant was particularly beneficial in a transmission charging zone as it was always available to accept bids and reduce output. The final version removed this flexibility test due to the difficulty of identifying the range. However, it was recognised that an incremental development to this proposal could be to gradually reduce the diversity benefit at load factors above 75% for low carbon/and or carbon plant to address this concern.

4.83 Under this potential alternative, maximum sharing (50%) occurs when there are equal proportions of low carbon and carbon plant behind a boundary. With either more or less carbon (or low carbon) this sharing reduces. The benefit is applied equally to all generators behind a boundary via a single part locational tariff, with no account being taken of a generator's individual annual load factor (i.e. tariff includes a common sharing factor). This approach is set out in full in Annex 4 and results in a two part wider TNUoS tariff as follows:

(YR x ZSF x TEC) + (Residual x TEC)

Where ZSF is the zonal sharing factor.

4.84 This Method is shown diagrammatically below in Figure 20.

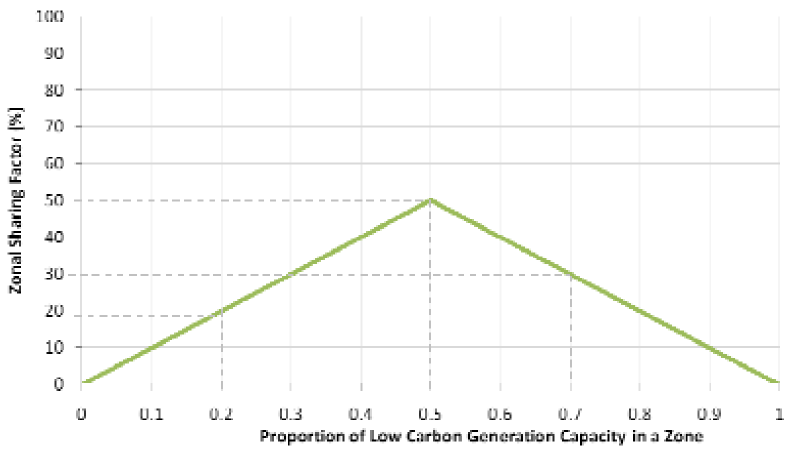

Figure 20 – Diagrammatical summary of Method 3

4.85 One Workgroup consultation respondent argued that the 50% maximum sharing element of this potential alternative should be removed, on the basis that two generators could share full capacity if they do not run at the same time. An alternative view was presented that the 50% sharing cap was only theoretical with two perfectly counter correlated plants, and in reality could be lower. Some other Workgroup members questioned the validity of the cap on sharing of 50% of MWkm in any charging zone.

4.86 Workgroup members supporting this potential alternative felt that it was the simplest of the diversity methods to apply and closest to the 'status quo' charging methodology that exists in the CUSC today.

4.87 It was also argued that this potential alternative recognises that:

- less transmission is built in areas with diversity and applies this to all generation in those areas;
- Sharing is the combination of generation and not the characteristics of an individual generator, as such reduced transmission network is built and TNUoS charges are applied in areas where sharing can occur;
- Whilst a generator's load factor is important for planning (methodology based on actual system) short term load factor is less relevant to transmission investment; and
- The replacement of the ALF scaling factor with ZSF will ensure that the efficiency of the wholesale market is not impacted.

4.88 However, some Workgroup members felt that this potential alternative was less cost-reflective than the Original or other diversity methods as it fixes the sharing factors to a group of generators rather than an individual generator, and that generators with widely varying load factors (i.e. plant that cause different costs on the transmission system) were treated the same.

4.89 It was also argued that this potential alternative does not take account of the fundamental cost benefit analysis undertaken by TOs which would lead to reduced transmission build.

4.90 Workgroup members supporting this potential alternative also suggested that this Method could be further extended to derive more granular sharing factors in future, for example by breaking sharing factors down for individual groups of generation of a similar type in an area. It was argued that this may make the Method more cost reflective in terms of apportioning benefits. Other Workgroup members felt that this extension would add complexity and volatility, would potentially treat certain generation plant types differently and relied on bid prices which were not a good measure of transmission build. It was also noted that additional granularity to support more specific treatment would require a more complex commercial information exchange. A further consequential effect of this is that it would be difficult for Users (especially smaller parties) to predict their TNUoS charges over the medium term, leading to market uncertainty.

4.91 Some Workgroup members believed that whilst this Method might address some of the negative transmission charging zone limitations with Method 1, others remained unaddressed.

4.92 Finally it was noted that this potential alternative in doing away with the 'dual background' approach and differentiation by plant characteristics could be considered to run counter to the Authority's SCR Direction. Some Workgroup members argued that it could be potentially not cost reflective to treat plant that leads to different transmission investments the same. It was noted this is already the case under 'Status Quo' and, as Method 3 reduces the absolute amount treated in this manner, it could be considered as an improvement on the baseline.

Discussion on assumptions used in the original proposal and sharing potential alternatives

Discussions on appropriate simplifications and the potential for discrimination

4.93 A number of Workgroup members raised concerns that elements of both the Original and the three diversity method potential alternatives were either overly simplistic or could be regarded as discriminatory.

4.94 Previously, the Workgroup had discussed the assumptions made under GSR009 in the SQSS. Where information that directly affected transmission investment decisions was not available, transmission system planners need to make assumptions. It had been noted that for the purposes of planning transmission boundaries, assumptions on generation plant type behind the boundary (GSR009 scaling factors) were not intended to establish an individual generator's behaviour, but rather to establish an aggregate flow on a transmission boundary. The Proposer noted this is why the Original did not use SQSS scaling factor for establishing individual charges; i.e. it did not reflect an individual generator's contribution correctly, but in aggregate did give a reasonable transmission boundary flow and therefore, in their opinion, could be used in the background.

4.95 A number of Workgroup members suggested that the Original proposal of (i) using generation load factors, and (ii) the application of sharing across the local boundary, was an example of over simplification. Work on seeking to better define where and to what extent sharing occurs led to the alternatives around diversity. Whilst seeking to more precisely reflect sharing it was recognised that this introduced additional complexity. However, even with more complex methods, some assumptions and simplifications are still required. For example, in defining the price effect under diversity, the Workgroup have developed categories, 'Low Carbon' and 'Carbon' plant, to reflect the impact of bid price on constraint cost and hence the need for investment. Whilst all plant in a category may not have a negative bid price, it was intuitive that certain classes of plant could generally be expected to have negative bid prices (see Annex 9). The alternative would be to use individual bid prices. However, previous attempts in modification proposals under the Transmission Access Review (TAR) process to receive more granular forecast data found that submission of additional information by generators, was either out of scope or not practical, and this was also rejected by the Workgroup during CMP213 discussions.

4.96 Whilst much of the Workgroup debate in this area focused on bids prices in negative areas, it was also understood that a similar simplification was made in importing zones on offer prices. For example, diversity Methods 2 and 3, provided a capacity benefit in the year round component to plant irrespective of its offer price; i.e. even if under a cost benefit analysis it was unlikely to reduce the need for transmission investments due to the high cost of offer acceptance. It was noted that this is already catered for in the baseline. Likewise, the Original and diversity Method 1 only provided a year round benefit to those Power Stations based on their actual running.

4.97 In terms of discrimination, the Workgroup understood that any simplification, averaging or use of generic factors could be considered as discriminatory. However, the baseline, the Original, and all of the alternatives included elements of these to varying degrees. Therefore, most of the Workgroup considered the issue more related to whether it was practical, or too complex to use only specific data, rather than whether it was discriminatory. Whilst, over and above this, some Workgroup members noted that diversity Methods 1, 2 and 3 were potentially discriminatory in the treatment of certain generation plant types, others believed such an argument could also be applied to the Original and even the baseline.

4.98 In summary, the Workgroup did not agree on which simplifications were appropriate, hence the number of alternatives presented which reflect a range of members views on simplicity and practicality vs. cost reflectivity and complexity.

Bath University report discussions

4.99 During the Workgroup consultation, RWE and Centrica commissioned Bath University to undertake a study to investigate "Year-Round System Congestion Costs – Key Drivers and Key Driving Conditions". The full report of this study can be found in Annex 13. This study examined the linearity between load factor and constraint costs and the appropriateness of introducing a dual background in charging.

4.100 This study concluded that transmission network sharing, as described in the pre Workgroup consultation CMP213 Original, did not represent an improvement on the baseline charging methodology.

4.101 Bath University presented the study's findings at a post-Workgroup consultation Workgroup meeting and the Workgroup discussed the report with the authors.

4.102 Much of the discussion focused around the purpose of TNUoS being to recover the cost of efficient transmission network investment rather than to minimise congestion costs per se. Some Workgroup members felt that the study had focused too much on the latter, and whilst in an optimally invested transmission network, short run and long run costs would have a perfect relationship, this is not reflected in reality, and is skewed by initiatives such as Connect and Manage. Some others also agreed that this is not the reality and noted that this is why the assumed relationship between load factor and constraint costs is not robust. The defect that CMP213 seeks to address is focussed only on improving the long run TNUoS signal which is to recover long term costs of transmission system build as opposed to short term constraint costs on the system. Recovery of short run System Operator costs (via BSUoS) is excluded from the scope of CMP213.

4.103 The Proposer noted that the use of a single pseudo-CBA background had been developed as part of the NETS SQSS work under the change proposal GSR009, and that a significant amount of cost-benefit analysis consideration underpinned the resultant background developed to replicate the year round effect of the National Electricity Transmission System. The Proposer also noted that the rationale for GSR009 was now accepted in the latest version of the NETS SQSS, rather than a proposal as inferred by the Bath University study.

4.104 The Proposer restated that the reason ALF was being used under the Original was that it was a proxy for the effect that a specific generator has on transmission system investment. It was recognised that whilst the generic scaling factors under GSR009 provided a suitable background for assessment, specific generators of a common technology could cause significantly different impacts on transmission investment based on their level of output over a sustained period . Hence, under the Original proposal ALF would be a longer term, plant specific annual load factor rather than by generation type.

Original – addition of CCF

4.105 Prior to the Workgroup consultation, it was discussed whether sharing should be considered on local transmission circuits (Annex 4, 4.268 – 4.348). It was argued that although historically, planning for local transmission circuits for generation has been normally done on the basis of generation plant capacity (MW), there may be more explicit sharing on local transmission networks in the future. It was believed that this might take place, particularly in the case of increasing amounts of renewable generation of differing technologies connecting to local transmission circuits, where there may be some counter-correlation of generation output.

4.106 Prior to the Workgroup consultation, analysis conducted by Heriot-Watt University had been presented (Annex 4, 4.298 – 4.316). This focused on the Orkney Islands as a case study, assumed to be connected via a local transmission circuit. Some Workgroup members believed that this analysis demonstrated that:-

- There is likely to be an economic case for building local transmission circuits that are sized under the combined rated capacity of the various generator technology types using (or expected to use) those circuits; and
- That this case holds for intermittent, renewable, generators sharing access to a local transmission circuit

4.107 Whilst some in the Workgroup were less sure about the conclusions of the analysis, the Workgroup were generally agreed with the principle that where the local transmission network is planned on the basis of there being network sharing by generators, that this should be reflected in TNUoS tariffs. Prior to the Workgroup consultation a number of possible solutions to this were discussed (Annex 4, 4.321 – 4.348), but no solution was agreed by the Workgroup as having no consequential issues.

4.108 After the Workgroup consultation, the Proposer presented a different potential solution to address issues around sharing on local transmission circuits, in order to reflect any counter correlation assumptions made when planning actual transmission constructed. The Proposer added a Counter Correlation Factor (CCF) to the Original proposal (presented below):

$$CCF = \frac{D_{min} + T_{cap}}{G_{cap}}$$

Where D_{min} = minimum annual net demand (MW) supplied via that transmission circuit in the absence of that generation using the circuit
T_{cap} = transmission capacity built (MVA)
G_{cap} = aggregated TEC of generation using that transmission circuit
And where the CCF is capped at 1; i.e. only comes into effect where there is sharing.

4.109 It was noted that CCF could apply to all radial transmission circuits where a TO had accounted for counter correlation of generation output when designing transmission capacity; i.e. even those that formed part of the MITS from a charging perspective. There was general agreement to this approach within the Workgroup, as it was believed that this conclusion removed any potential difference in treatment between circuits treated as wider and local.

4.110 In all cases the CCF would act in a similar manner as an expansion factor, by effectively 'contracting' the relevant circuit by the CCF factor, thereby producing a smaller marginal kilometre to reflect the additional cost of investing in the relevant circuit compared to 400kV overhead line.

4.111 It was noted that at this stage, there were no transmission circuits to which this factor would be below 1, but that this solution would ensure that counter correlation can be taken into consideration if sharing on local transmission circuits is taken explicitly into consideration by TO planning in the future, or where built circuits are subsequently used in this way.

4.112 Some of the Workgroup considered that there may be a case for different renewable generation technology types sharing anywhere on the NETS. The Proposer noted that ELSI accounted for regional variations in wind output and that this provided some level of consideration within the analysis presented on sharing in general. Others in the Workgroup noted that it would be difficult to quantify a suitable de minimus level; i.e. would different turbines of a single wind farm have counter correlation? Ultimately the Workgroup concluded there had been insufficient evidence presented to take this forward as a potential alternative.

4.113 The Workgroup discussed whether a CCF could be established earlier, prior to the connection of expected generation. This arguably provides more certainty to Users considering connecting to peripheral parts of the transmission system. It was noted that, in such timescales, the make-up of this generation would not be known, and therefore the level of counter correlation could not be accurately predicted. However, it was noted that the potential for using a future contracted background may assist in mitigating this uncertainty to an extent.

Original – change in MITS definition

4.114 Prior to the Workgroup consultation, the Workgroup discussed potential issues with the definitions of the Main Interconnected Transmission System 'MITS' (Annex 6, 6.15 – 6.54) when applying the Original proposal on sharing.

4.115 The Original proposal applies the principles of sharing set out within it to all parts of the transmission network considered to be part of the Main Interconnected Transmission System (MITS); i.e. 'wider'; for TNUoS charging purposes. Implicitly this would also include island connections that are classed as 'wider'.

4.116 There was concern expressed by the Proposer and some Workgroup members specifically around radial transmission circuits for islands connecting to the MITS, and their classification as wider rather than local. This is because under the Original proposal, a sharing factor based on a generator's ALF is applied to the wider element of the TNUoS tariff as a proxy for its impact on incremental constraint costs. The Workgroup had discussed how this relationship deteriorated as the amount of low carbon generation increased behind a transmission boundary (see 4.16). The Workgroup considered that on islands, future generation developments will result in high ratios of low carbon to carbon generation. Under the Original, some Workgroup members felt that using generator ALFs would lead to a reduction in cost-reflectivity in such situations. This would also be exacerbated by the high unit costs of transmission cables connecting this generation to the MITS on 'mainland' GB. It was argued that this effect would be so large as to make the Original proposal untenable. Under the three diversity method alternatives, this would be naturally taken into account and would be less of an issue.

4.117 Prior to the Workgroup consultation, a solution was proposed to divide the expansion factor for islands connected by a single transmission circuit by 1.8. However, there was concern around whether this would create a disparity between islands classed as local and wider under the Original.

4.118 Following the Workgroup consultation, the Proposer proposed a change to the definition of the MITS (for the purposes of the charging methodology only) to change the local/wider definition to go deeper into the transmission network, so that radial transmission circuits would not be classified, for charging purposes, as part of the MITS. This definition would class single sub-sea connections to islands as local, and would also be applied to other onshore radial transmission circuitry.

4.119 The Proposer confirmed that the Original would contain a revised charging definition for MITS as follows (addition shown in italics)

Main Interconnected Transmission System (MITS) nodes are defined *from a charging perspective* as:

1) Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
2) connections with more than 4 transmission circuits connecting at the site.

Other than where export from a ***Power Station*** *to the main* ***National Electricity Transmission System*** *is dependent on a single transmission circuit.*

4.120 As part of the presentation of this solution, the Proposer presented results of the analysis on the impact of introducing the solution. Currently the only affected non-island transmission circuit in GB identified by National Grid was the existing 132kV route via Broadford to the Western Isles in the SHE-T (TO) area.

4.121 The Workgroup queried what happens to sharing assumptions for Users classed as local if the local/wider definition is changed. It was confirmed that if sharing assumptions were built into the TO planning assumptions this would be dealt with in the charging methodology by the inclusion of the Counter Correlation Factor (see 4.105-4.113).

4.122 The Proposer noted that this proposed change to the charging definition of the MITS node would only be required for the Original proposal, as those potential alternatives accounting for diversity would naturally limit the concerns raised in paragraph 4.116, and there would be no requirement to change the existing definition on this basis.

4.123 The Workgroup discussed whether a separate sharing definition of MITS node may be appropriate. This would mean not changing the charging definition of MITS node to class all radial transmission connections as local, but use the proposed updated definition as a new sharing definition of MITS node. It was noted that this option would be complex to establish in practice within the Transport Model.

4.124 Whilst some in the Workgroup felt that this option may have merit, others argued it would be an overly-complex solution to introduce an additional charge calculation for all, when the resultant effect would be the same as the amended definition under the Original proposal.

4.125 Some of the Workgroup expressed concern over the potential for changes to the charging definition of MITS node on User Commitment arrangements. The Proposer confirmed that User Commitment arrangements have a separate 'Attributable Work' definition of MITS node and there was no codified or actual linkage between that definition and the charging definition of MITS proposed for CMP213. Hence there would be no effect.

4.126 On this basis a majority of the Workgroup felt that the Proposer's solution was an adequate solution to the issue and therefore a separate sharing definition of MITS node was not taken forward by the Workgroup.

b) Alternative approaches to Annual Load Factor (ALF) for reflecting user characteristics into charging

4.127 The CMP213 Original proposal is for the Year Round element of the TNUoS tariff to be scaled by a generator specific sharing factor, based on the annual load factor (ALF) of that generator. This is to better reflect the impact that generators with different plant characteristics have on the incremental cost of transmission network capacity, than is possible under the current charging methodology approach. The purpose of cost reflectivity within the TNUoS charging methodology is to allow individual generators to take the cost of transmission into account when making decisions about where to locate new plant and when to close their existing plant.

4.128 The CMP213 Original proposed to calculate this generator specific ALF by using the last five years' load factors for the individual Power Station concerned, and calculating an average of the middle three values (i.e. ignoring the highest and lowest values) as a proxy for the implicit assumptions made when planning investment in transmission network capacity. This is illustrated in Figure 21, below:

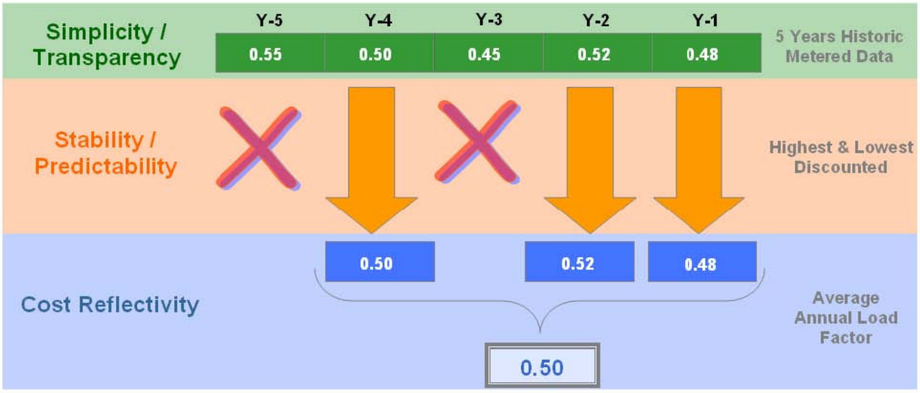

Figure 21 – Calculation of ALF in the Original

4.129 Prior to the Workgroup consultation, a range of alternatives to using ALF as proposed in the Original were considered. The full descriptions and Workgroup discussions on these can be found at Annex 4. These are listed in Table 14 below.

a) Alternative approaches to ALF for reflecting User characteristics into charging	i) TEC only
	ii) SQSS based generic factor
	iii) Other Generic load factor
	iv) NGET and/or User forecast
	v) Hybrid approach
	vi) Alternatives measures (metered, FPNs)
	vii) Ex-ante or ex-post

Table 14 - Alternative approaches to ALF for reflecting User characteristics into charging

4.130 Other areas highlighted for potential development by Workgroup consultation respondents included whether historic ALF could be done over a shorter than five year period, and whether a sharing factor could be produced by a market model, although no specific alternatives were raised on these.

4.131 After the Workgroup consultation, four potential ALF alternatives were discussed further by the Workgroup:

(i) Generic factors
   a. SQSS based generic factor
   b. Generic Load factor by technology type
   c. Generic Load factor by broader technology groupings

(ii) Hybrid approach

Generic factors

4.132 Some in the Workgroup argued that using generator specific ALFs, as in the CMP213 Original proposal, may affect the pricing decisions of generators, particularly in the shorter term. It was argued by these Workgroup members that a new variable cost of generation element is created with the use of ALF. The lagging effect inherent in the ALF calculation makes it very difficult for generators to accurately price this variable cost which is likely to impact the efficiency of the wholesale market. The use of generic load factors was proposed to negate this impact.

4.133 An illustrative example was shared by a Workgroup member to show how they believed a generator would incorporate variable costs of generation (as a result of a changeable ALF year on year) into their Short Run Marginal Cost. This can be found in Annex 14.1.

4.134 As a result of this analysis, the Workgroup member put forward three options for consideration.

(a) SQSS based generic factor

This potential alternative would use the background scaling factors set out in GSR-009, updated when the SQSS is updated.

(b) Generic Load Factor by technology type

This potential alternative would use generic load factors based on historic data. Generic data would be derived from the average annual output of all GB generation of a particular fuel type over the last five years, using the same methodology as proposed in the Original for the User specific calculation of ALF.

(c) Generic Load Factor by broader technology groupings

4.135 This potential alternative was put forward on the basis that using a generic load factor on a broader generation type grouping, as shown in Table 15 below, would have merit by further diluting the relationship between generator production and transmission cost variations.

Generation Type	Consists of
Conventional	Coal, Gas, Biomass, Oil
Weather related	Wind, Hydro
Pumped Storage	Pumped Storage
Nuclear	Nuclear

Table 15 – Generation type grouping

4.136 Those in support of the three generic options argued that decreased granularity of groupings would offer more stability to generators who would have difficulty internalising the time lag of the variable cost component associated with the five year ALF approach set out in the Original proposal.

4.137 Some Workgroup members felt that the complexity associated with pricing this variable cost would likely be factored into generator's short run pricing decisions in the wholesale electricity market. Some Workgroup members also questioned the proposed cost reflectivity benefits associated with a specific ALF scaling factor as it is unclear what signal is being developed for generation and how it would be expected to react to this signal. As such it is unclear how the proposed more cost reflective signal will translate into helping optimise total power system costs (generation & transmission).

4.138 Those in the Workgroup who did not support the use of generic load factor groupings felt that broader generic load factor groupings were less cost reflective than the more granular generic groupings or User specific ALF.

4.139 There was some support for generic options from Workgroup consultation respondents, and of these the SQSS based generic factor was preferred.

4.140 After discussions on the elements that would be carried forward into potential alternatives, there was not majority Workgroup support for any of the generic ALF options, so these were not taken forward.

Hybrid approach

4.141 An approach was discussed prior to the Workgroup consultation, which would allow each generator to decide (on an annual basis; possibly with a year and 5 days notice or the November prior to the start of the charging year in April) whether to accept National Grid's ALF figure for its Power Station (the CMP213 Original proposal) or whether to submit its own forecast of the power station's ALF for the next charging year. This was deemed, by the Workgroup, as the "hybrid" approach as it combined elements of using National Grid's five year based ALF figure and a generator's own forecast ALF figure.

4.142 There was some support from Workgroup consultation respondents on the hybrid option, and the User forecast element. Those supporting User forecast elements, argued that this would allow TNUoS to remain forward-looking, as it would give the generator an opportunity to signal what they plan to use (in terms of transmission network capacity), rather than holding generators to their past plant performance.

4.143 This led to the development of the following potential alternative:

1) National Grid will calculate the ALF for each individual Power Station connected to the transmission system on the basis of the average of the last 5 years (for renewable generation) or the average of last 2 years (non-renewable generation[8]) by 30 September in each charging year (t-1).
2) Each Power Station will then have the option to submit their own forecast ALF by 31 October each charging year (t-1) where they anticipate their ALF in the next charging year (t) will be materially different from National Grid's figure provided under (1) above. National Grid will use this forecast provided by the Power Station in calculating TNUoS tariffs to apply in the next charging year (t).
3) At the end of the charging year (t), National Grid will calculate the actual ALF for each individual Power Station connected to the transmission system by 31st May (t+1), which would then be compared to the power station's forecast under (2) above (where submitted).
4) Where the difference between the Power Station's actual ALF and forecast ALF is less than 2% (tolerance band) no further action will be taken by National Grid.
5) Where the Power Station's actual ALF exceeds the Power Station's forecast ALF by more than 2%, the excess above 2% will be charged at 1.5 times that Power Station's applicable TNUoS charge in the charging year (t).
6) Reconciliation payments (calculated according to (3) –(5) above) will fall due for payment, by the Power Station, 30 Working Days after the date of invoice by National Grid
7) As National Grid will have recovered its full Allowed Revenue through the actual TNUoS tariffs levied on generators during the charging year (t), there will be no cash-flow impact for National Grid and any additional TNUoS revenue received from generators' reconciliation payments

[8] For the avoidance of doubt, biomass will be treated as non-renewable generation.

(under (6) above) will effectively be an over-recovery from one charging year (t) arising in the next charging year (t+1).

8) Any TNUoS over-recovery value will be returned to generators in proportion to their TEC (MW) value in the preceding charging year's (t) charging model (i.e. on the same basis as the residual element of the TNUoS charge) within 90 Working Days of the end of the charging year (t).

4.144 The Workgroup supporter of this hybrid option confirmed that interest would be chargeable on reconciliation payments arising under (6) above consistent with interest charging on other reconciliation payments arising currently under the CUSC, using Barclays Base Rate. This reconciliation payment would be calculated as part of a separate process and billed separately (i.e. not netted off current (t+1) or other charging years ((t) or (t-1)) charges). It was noted that this may require a change to Section 3 of the CUSC, which may necessitate a supplemental Modification proposal as CMP213 relates to changes to Section 14 of the CUSC only.

4.145 It was also confirmed that under this potential alternative National Grid would have the right to challenge Users' forecasts using a process similar to that for Demand as set out in paragraph 14.17.17 of the CUSC; e.g. use the historic 5 year ALF for comparison and request explanation of differences from Users. Other than plant failure or outage plans, similarities in groups of generators should be observed.

4.146 With regards to negative TNUoS charging zones, under this option generators have to demonstrate their generation capability over the winter period in order to qualify for a (TNUoS) payment. The Workgroup discussed the potential for interactions between operational payments made to generators to manage system congestion, and any TNUoS payment made. It was agreed that there was no interaction, as generators would factor in any additional potential reconciliation excess payments into their offer prices. However it was noted that, for the avoidance of doubt, the 2% collar on User forecast excess charges would still apply with reconciliation payments being due from the generator to National Grid (i.e. positive rather than negative).

4.147 There would be a number of consequential changes to the billing systems to affect the submission and over-recovery payment associated with this option.

4.148 There was majority support within the Workgroup for this to be taken forward as a potential alternative.

c) Whether intermittent generation technology types should be exposed to the peak element of the tariffs

4.149 The Original proposal would split the existing wider locational element of the TNUoS tariff into two elements, (i) the Peak Security element and (ii) the Year Round element, consistent with the use of different backgrounds in transmission planning introduced into the NETS SQSS through GSR-009.

4.150 In addition, the Original proposal would levy the Year Round element on all generation plant types in proportion to their individual ALF (a generator specific % load factor) and TEC (MW), whereas intermittent plant types would not be exposed to the Peak Security element, on the basis that these plant are not considered present at times of peak demand when planning transmission network capacity at times of peak demand (i.e. the NETS SQSS does not plan capacity for intermittent generation at peak). However the Proposer confirmed that, should the NETS SQSS be altered such that consideration was taken of intermittent plant at peak, the exposure of such plant to the Peak Security element should be reconsidered. For the avoidance of doubt, such a reconsideration would, in the context of the charging methodology, require (if appropriate) a new CUSC Modification proposal to be raised.

4.151 The resulting TNUoS tariff structure is shown in, Figure 22 below.

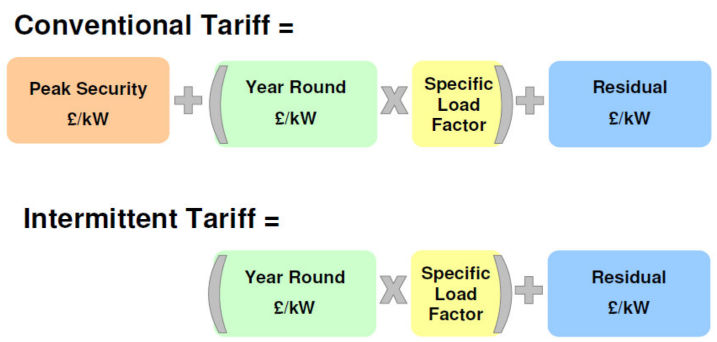

Figure 22 – Tariff structure in the Original Proposal

4.152 The Authority's SCR Direction specifically set out a consideration of whether intermittent generation technology types should be exposed to the Peak Security element of the TNUoS tariff. Prior to the Workgroup consultation, the Workgroup considered two possible changes to the CMP213 Original that could be made (fully discussed in Annex 4, 4.249-4.267):

i) That intermittent plant be exposed to the Peak Security element to some extent; or

ii) That intermittent plant exposure to the Peak Security element be index-linked to an appropriate factor.

4.153 In terms of the Workgroup consultation responses, some respondents felt that intermittent generation plant should be exposed to the Peak Security element of the TNUoS tariff, whereas other respondents felt that further consideration should be kept under review (e.g. to link with the SQSS), but no formal alternatives were raised on these.

4.154 After the Workgroup consultation, exposing intermittent generation plant to the Peak Security element of the TNUoS tariff did not have majority Workgroup support. However, it was noted that intermittent generation technologies would be treated the same as non-intermittent generation technologies under the diversity Method 3 potential alternative.

Other potential alternatives

4.155 A range of other potential alternatives were discussed prior to the Workgroup consultation, as in Table 11. Following the Workgroup consultation, the following two other potential alternatives were discussed:

Post- consultation Potential Alternatives
i) Don't have a dual-background (YR only)
ii) Use of a full market model to calculate charges (more than 2 backgrounds)

Table 16 – Post-consultation Potential Alternatives

Single background – YR only

4.156 Prior to the Workgroup consultation, some members of the Workgroup raised the possibility of not utilising a dual (Peak Security and Year Round) background approach and, instead, calculating TNUoS tariffs on the Year Round background only, thus leading to only a single element of the wider locational TNUoS tariff on the basis that this would be less complex and, in their view, potentially more robust.

4.157 One Workgroup consultation respondent highlighted that further consideration should be given as to whether transmission charging should take place on a single background (existing, Peak Security or Year Round), and applying ALF to this tariff.

4.158 The Workgroup confirmed their pre-Workgroup consultation view that the use of the Year Round background could only form part of a potential alternative to address the issues of generation plant diversity (i.e. diversity Method 3).

Full Market Model

4.159 Prior to the Workgroup consultation, the Workgroup discussed the potential for an alternative that would use a full market model to set TNUoS tariffs (Annex 4, 4.359-4.364). At this point, the Workgroup decided not to proceed with the development of this option as they felt that the drawbacks of the option outweighed the anticipated benefits. These drawbacks included the need to obtain all the relevant information for the model, as well as updating and running the complex model each year. Another drawback identified was that it would reduce transparency and predictability of TNUoS tariffs.

4.160 During the Workgroup consultation, one respondent felt that this option should be developed further. After the Workgroup consultation, a potential alternative using a full market model option was suggested by a Workgroup member. Under this potential alternative, TNUoS tariffs would be derived through running a full nodal economic model of the transmission system for a set number of snapshots representing a year of operation of the transmission system. A load flow assessment based on the current ICRP methodology would be carried out for each node in turn for each of these snapshots, and from these the incremental MWkm would be derived for each snapshot. From these snapshots, a demand weighted average incremental MWkm would be derived for the year, and converted into generation TNUoS tariffs.

4.161 During initial discussions, the Workgroup identified that there were a number of issues that would need further work should this potential alternative be taken forward. In particular, the Workgroup were unclear as to how input assumptions for such a model would be developed by the System Operator and the level of agreement that would be required with industry, and how this interacted with short term cost signals.

4.162 Some Workgroup members could not (from the information presented to the Workgroup by the Workgroup member who suggested this potential alternative) understand the application or intent of this potential alternative. Other Workgroup members felt that this potential alternative would not address the defect. There was some further discussion of deriving technology-specific sharing factors based on load factors assumed in each of the model runs. However, this again was considered complex and subject to modelling assumptions.

4.163 On the basis of the above the Workgroup agreed not to proceed with the development of this option.

Summary of elements taken forward into WACMs

4.164 Following initial post-Workgroup consultation discussions, the Workgroup undertook a round of informal voting to consider which potential alternative elements should be taken forward into WACMs. The elements taken forward to be combined into WACMs were

- Diversity Method 1
- Diversity Method 2
- Diversity Method 3
- ALF - Hybrid option

Other issues covered

4.165 Under CMP213, it is necessary to amend the legal text for STTEC and LDTEC. This is because there are now two different tariffs to be considered. To ensure there is a continuing methodology for treatment of these elements, the legal drafting has included clarification of how these will be charged for the Original and each of the Diversity potential alternatives.

4.166 Prior to the Workgroup consultation, the need for a potential consequential CUSC Modification Proposal to review the calculation of STTEC and LDTEC was discussed (Annex 4, 4.439-4.441). No specific comments on this were received during the Workgroup consultation, however the Workgroup noted that the rationale for these products would be required to be reviewed following implementation of the Original, or any of the potential alternatives developed.

5 Summary of Workgroup Discussions on HVDC

Introduction

5.1 The HVDC aspect of the CMP213 Modification proposal seeks to keep TNUoS tariffs up to date with transmission business developments through incorporating parallel HVDC transmission circuits into the TNUoS charging methodology. It does this by addressing two issues:

(i) treatment of flows in the DC load flow element of the charging model, in light of the inherent controllability of power flows through an HVDC transmission circuit; and

(ii) calculation of an appropriate expansion factor (i.e. relative unit cost) for these HVDC transmission circuits.

5.2 The CMP213 Original proposal would treat power flows on HVDC transmission circuits as if they were AC circuits (i.e. as pseudo AC circuits).

5.3 This would be done by first calculating a base case flow down the HVDC circuit, which would subsequently be used to calculate the notional impedance for it in the Transport Model. The base case flow down the HVDC transmission circuit would be calculated from a ratio of power flows to circuit ratings across a transmission network boundary 'crossed' by the HVDC circuit. This approach would calculate a desired power flow for the HVDC circuit on each transmission boundary that the link 'crosses' and then average this flow across those multiple transmission boundaries.

5.4 In terms of the calculation of the expansion factor for an HVDC transmission circuit, the Original proposal would do so on a transmission circuit specific basis and would include both sub-sea cable and the HVDC converter station costs. This approach is consistent with offshore (OFTO) arrangements, where both costs are included in the circuit expansion factor calculation for HVDC.

Summary of Workgroup and consultation discussions to date

5.5 This section of the report is intended as a summary of discussions to date. Workgroup discussions after the Workgroup consultation can be found in this section, referencing the pre-Workgroup consultation discussions and Workgroup consultation responses where applicable. Further details of the Workgroup debate prior to the Workgroup consultation can be found in Annex 5 and consultation responses in Volume 3.

5.6 The Workgroup was asked to report on the following specific issues by the CUSC Panel as part of their Terms of Reference, which were in line with / in addition to those set out in the Authority's SCR Direction (appropriate report paragraphs from Workgroup discussions referenced):

g) how often the parameters associated with the proposed approach should be updated (e.g. annually, every 4 years, every 8 years) (Annex 5, 5.13 and legal text)

5.7 The Workgroup agreed the areas to be considered for the HVDC aspect of the CMP213 Original proposal could be summarised as:

Considerations from the Direction	Potential changes to Original
a) Whether the cost of HVDC converter stations should be	i) Remove all converter station costs from the calculation

Considerations from the Direction	Potential changes to Original	
included in the expansion factor calculation	ii)	Remove some converter station costs from the calculation
	iii)	Treat HVDC cost as onshore AC transmission technology cost when calculating the expansion factor

Table 17 - Areas for development of Original and potential alternatives

5.8 Prior to the Workgroup consultation, the Workgroup also discussed further areas where the CMP213 Original could be developed (that were not highlighted by the Authority's SCR Direction), and discussed each of these in turn.

Potential Alternatives	
i.	Review the overhead factor (i.e. 1.8%) used when annuitising the capital cost in the calculation of the HVDC expansion constant
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'
iii.	Review security factor calculation in light of long (MWkm) HVDC links comprised of single transmission circuits that parallel the AC transmission network

Table 18 – Discussion on the Original and potential alternatives

5.9 A majority of the Workgroup agreed that these areas should not be developed further as potential alternatives, based on both evidence provided to the Workgroup and responses to the Workgroup consultation.

Discussion on the Original proposal and potential alternatives

a) Whether the cost of HVDC converter stations should be included in the expansion factor calculation

5.10 The Workgroup noted that there are basically two cost elements associated with HVDC transmission circuit, namely (i) the cost of cables, both sub-sea and underground, and (ii) the cost of the onshore converter stations that convert the electrical current between AC and DC so that it can be transferred along the cable routes.

5.11 The Original proposal would include 100% of the costs of both the HVDC converter stations and the cables into the expansion factor calculation. This is deemed to be consistent with the approach taken for offshore (OFTO) transmission TNUoS tariffs. A number of respondents to the Workgroup consultation highlighted their support for the Original proposal to include 100% of these costs. However a number of respondents did not agree with this approach, highlighting that it was inconsistent with onshore transmission charging in the expansion factor calculation

5.12 The Workgroup investigated alternatives to this approach.

Remove 100% of HVDC converter station costs from the calculation

5.13 The Workgroup discussed a potential alternative where 100% of the cost of the HVDC cables would be included in the expansion factor and 100% of the cost of the onshore converter stations would be excluded from the expansion factor calculation.

5.14 Those in support of the removal of 100% of the HVDC converter station costs from the calculation believed 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. For example, it could be argued that converters would have broadly the same function as transformers in that they effectively link different elements of the transmission system. In addition, it can be argued that converters 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).

5.15 Some Workgroup members and consultation respondents thought that removal of converter station costs achieved better equivalence with the cost reflectivity of onshore expansion factors, which do not include all cost elements; e.g. tunnelling. Other arguments for excluding converter station costs were that they represented a significant proportion of costs, which would distort TNUoS tariffs. Some Workgroup members felt that, as the choice of transmission system technology is driven by the UK and Scottish Government's climate change targets and planning consent difficulties, plus time delays associated with building onshore transmission circuits, TNUoS charge payers alone should not have to bear the full extent of the TNUoS tariff increase through the locational element for HVDC technology. Indeed, without the removal of these fixed costs, the resulting TNUoS charges may prevent the investment in the very generation that the HVDC cables are intended to serve.

5.16 After the Workgroup consultation, a paper was circulated to provide further information and justification around this potential alternative area. This can be found in Annex 14.3. Further information on this can also be found in Annex 14.10.

5.17 The Proposer argued that in order to use HVDC cable technology, converter stations are necessary and that these converter stations add to the cost of this transmission technology and, as such, the full cost of the converter stations should be included in the locational TNUoS signal.

5.18 Those in support of including 100% of the converter station costs in the expansion factor calculation also argued this provides the correct market signal as it enables Users to properly take account of the cost of transmission when deciding where to locate their generation plant. These Workgroup members argued this may result in a benefit to consumers in the long-term.

5.19 At an initial vote on potential alternative elements, a majority of the Workgroup voted that this element (100% of the converter station costs should be excluded from the expansion factor calculation) should not be taken forward.

Remove some HVDC converter station costs from the calculation

5.20 Prior to the Workgroup consultation, the Workgroup identified two possible alternatives for the removal of a portion of the HVDC converter station costs from the expansion factor calculation:

i) Remove a ***generic*** percentage of the costs based on those elements of the HVDC converter station that are similar to elements of the AC transmission network, that are currently not included in the locational signal (such as transformers); and/or

ii) Remove a portion of the costs based on the similarity between the power flow redirecting capability of HVDC current source converters and that of QBs that are currently not included in the locational signal.

5.21 After the Workgroup consultation, the following options were also discussed:

iii) Remove a ***specific*** percentage of the costs based on those elements of the HVDC converter station that are similar to elements of the AC transmission network that are currently not included in the locational signal (such as substation equipment); and

iv) Remove a proportion of HVDC costs in line with the proportion of socialised costs on the AC system.

5.22 During the Workgroup consultation, a number of respondents supported removal of a proportion of the converter station costs from the HVDC expansion factor. The majority of those supporting this option had a preference for removing costs equivalent to AC substations.

5.23 All four of these potential alternatives are discussed in further detail below.

<u>i) Remove a ***generic*** percentage of the HVDC converter station costs based on elements similar to AC substations</u>

5.24 The TNUoS charging methodology currently does not include the majority of the costs of the transmission network that do not vary with distance, such as substation costs, in the calculation of expansion factors. On this basis, and the fact that a proportion of HVDC converter station costs can be related to AC substation equipment, the Workgroup believed that a possible alternative to the Original proposal could be to remove those AC cost elements from the calculation of the expansion factor; i.e. it would socialise AC cost elements (across all Users). This approach would retain the DC elements, such as the switching equipment, required for the use of DC cables; i.e. it would charge those DC cost elements locationally.

5.25 The Workgroup considered (prior to the Workgroup consultation) some analysis (Annex 5, 5.32) previously undertaken which indicated that approximately half the cost of the HVDC converter station component elements exhibited characteristics equivalent to the AC network, with the remaining cost elements exhibited characteristics equivalent to the DC network.

5.26 Those supporting this option argued that in addition to creating consistency with AC substation equipment, it would also provide a greater degree of stability and predictability to transmission system users if the percentage of HVDC converter station costs to be included in the expansion factor was codified in advance.

5.27 After the Workgroup consultation, a paper was circulated to provide further information and justification around this potential alternative area. This can be found in Annex 14.4. This included further evidence reinforcing the validity of the Cigre cost breakdown provided prior to consultation (that approximately half of the basic cost elements of the HVDC converter station have characteristics equivalent to AC and the other half to DC), including confirmation from a technology supplier that the breakdown is representative of current converter technologies. It also highlighted that under turnkey contracting arrangements, specific cost details are difficult to obtain and so this supports a generic approach.

5.28 At an initial vote on potential alternative elements, the majority of the Workgroup voted that this element (remove a generic % from the expansion factor calculation) should be taken forward.

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

5.29 The Workgroup also considered the controllability of HVDC transmission circuits and the potential benefits that may be afforded to the System Operator as a result of this controllability. Some in the Workgroup believed that these benefits should be reflected in a reduction of the expansion factor.

5.30 One item of transmission technology that does allow the System Operator to better utilise existing transmission network capacity is the QB, which can be used to redirect power flows on transmission circuits. As such, this benefit could be considered to be relevant to the incremental cost of transmission capacity. Some Workgroup members believed that as QBs were not currently included in the locational signal for AC circuits, the equivalent cost should also be removed from the HVDC expansion cost calculation.

5.31 When considering available evidence prior to the Workgroup consultation, the Workgroup considered if QB costs were to be removed from the HVDC converter station cost element, that this would likely amount to the order of a 10% cost reduction to the converter station (i.e. 3% to 5% of the total HVDC link cost).

5.32 Some of the Workgroup believed that, whilst there is a controllability benefit for parallel HVDC links (e.g. the planned HVDC Western and Eastern 'bootstraps' will use Current Source Converters), these benefits are likely to be somewhat nebulous, difficult to quantify and whilst they may result in a lower operational costs (charged through the BSUoS tariff), they were unlikely to be relevant to the incremental cost of transmission capacity upon which TNUoS charges are based and expansion factors are calculated.

5.33 At an initial vote on potential alternative elements, the majority of the Workgroup voted that this element (remove a QB related % from the expansion factor calculation) should be taken forward

<u>iii) Remove a ***specific*** percentage of the costs based on those elements of the converter station that are similar to elements of the AC transmission network that are currently not included in the locational signal (such as substation equipment)</u>

5.34 It was suggested that removing a specific amount from HVDC converter station costs on a case by case basis may be an improvement on the other alternatives that removed a generic amount, and also the Original, which removed none of the converter station costs. This was on the basis that some Workgroup members felt there to be 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. As this was the rationale for specific recovery of costs in offshore transmission charging, these Workgroup members believed that this would ensure equal treatment of Users and avoid any potential for discriminatory arguments. It was also argued that using this approach would be more cost-reflective. The supporter of this potential alternative noted that there are likely to be relatively more offshore networks than bootstraps and links to islands, and therefore could not see how collecting information for HVDC links would be any more onerous so as to justify a different approach. However, other Workgroup members felt that it may not be possible for a National Grid to acquire the necessary information to implement this proposal. A paper describing this potential alternative can be found in Annex 14.5.

5.35 In this potential alternative, calculating the expansion factor for each HVDC converter station would be done by removing the specific costs for those elements of an HVDC converter station that would be equivalent to an AC substation on a case by case basis, rather than relying on a generic proportion. Such a calculation would be carried out at the same time as other parameters, such as the expansion constant, to ensure that relative costs are still reflected in the charging methodology. However, with this potential alternative if no specific cost breakdown (for the HVDC converter station cost elements) was available, perhaps because the TO purchase contract was on a turnkey basis, then the default generic information would be used (see 5.24-5.33).

5.36 At an initial vote on potential alternative elements, the majority of the Workgroup voted that this element (remove a specific % from the expansion factor calculation) should be taken forward.

iv) Remove a proportion of HVDC costs in line with the proportion of socialised costs on the AC system**.**

5.37 A potential alternative was explored whereby the total offshore HVDC system costs (cable and converter stations) are treated in a similar manner to the onshore AC system costs (overhead line / cable and substation), by apportioning the costs associated with the transmission technology to the circuit and socialising elements in the same proportion as occurs on the AC system. It was felt that this would be both a simpler solution to removing a generic percentage to reflect the AC elements, and would reflect the "pseudo-AC" approach being taken forward in the modelling flows associated with HVDC transmission circuits. A paper describing this potential alternative can be found in Annex 14.7. In effect this would be done by calculating the proportion of fixed costs in the Regulatory Asset Values (RAV) for all onshore TOs divided by the total costs, to work out a set percentage of costs to be socialised across each HVDC system. This is as follows:

(fixed costs on AC RAV/total AC RAV) = % of HVDC costs socialised

5.38 The Workgroup member raising this as a potential alternative felt it to be a simpler solution to the apportionment of costs, does not rely on potentially commercial confidential information about the design of HVDC systems, can be applied consistently to the 'Bootstraps', island connections, and offshore connections, and should remain relatively stable over time.

5.39 The Proposer noted that the RAV for a TO is not sufficiently granular to identify specific transmission asset types and volumes, and that this would make a direct assessment impossible. However, it was acknowledged that a rudimentary assessment could be undertaken if certain assumptions were made.

5.40 As the Workgroup member suggesting this option believed that there were sufficient potential alternatives under discussion to cover the range of potential HVDC cost options, this option (remove a proportion of HVDC costs in line with the proportion of socialised costs on the AC system) was not taken forward.

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

5.41 Some of the Workgroup believed, in the case of the Western HVDC link, that it should be treated in exactly the same way as the equivalent parallel (onshore) AC 400kV transmission circuits in the TNUoS charging methodology.

5.42 These Workgroup members believed that to do otherwise would be to unduly discriminate against certain Users, as Users exposed to HVDC link costs would receive a higher TNUoS charge than an equivalent AC link.

5.43 The Proposer explained how an overall investment decision of a project such as the Western HVDC link, considered the timing of an equivalent onshore reinforcement and the operational costs incurred during the intervening period whilst this reinforcement was constructed. Ultimately, the investment decision is based on the most economic decision for the GB consumer.

5.44 The onshore reinforcement would also include a broader suite of reinforcements including potentially greater lengths or capacities or overhead lines or cables, and that there may be significant substation upgrades required. This, argued the Proposer, significantly reduced the accuracy of any simple attempt to compare costs directly.

5.45 In the view of some Workgroup members this should result in a discount, on the HVDC TNUoS charge, to reflect the constraint costs saved (over the period of time in question). However, other members of the Workgroup noted that constraint costs were not charged locationally, and therefore argued that no direct comparison could be made.

5.46 This potential alternative area was developed further following the Workgroup Consultation (the supporting paper can be found in Annex 14.8). Evidence was cited by a Workgroup member that the equivalent required onshore capacity for the 2.2GW Western HVDC link was 3.4GW, and proposed a set of expansion factors based on these capacity ratios for equivalent AC circuits, as shown in the Table 19 below.

Option	**Onshore capacity (GW)**	**Notes**	**Expansion factor for HVDC capacity (2.2GW)**						
A	equal	Capacity of the Western HVDC link	*1.00*						
B	2.2	Capacity of the Western HVDC link	**1.00**	**1.55**	**2.00**	**3.00**	**3.09**	**4.00**	**10.00**
C	3.4	Onshore capacity modelled by TOs		*1.00*					
D	4.4	Onshore twice the option A capacity			*1.00*				
E	6.6	Onshore three times the option A capacity				*1.00*			
F	6.8	Onshore twice the option C capacity					*1.00*		
G	8.8	Onshore four times the option A capacity						*1.00*	
H	22.0	Onshore ten times the option A capacity							*1.00*

Table 19 – Proposed expansion factors based on capacity ratios for equivalent AC

circuits

5.47 At an initial vote on potential alternative elements, the majority of the Workgroup voted that this element should not be taken forward.

Potential Alternatives

5.48 Following the Workgroup consultation, other potential alternatives in this area (listed in Table 18) were not taken forward and there was little support for these from respondents to the Workgroup consultation.

5.49 At a post-Workgroup consultation meeting, an additional potential alternative was raised by a Workgroup member, discussed below.

<u>Fix HVDC expansion factors at T-4</u>

5.50 Some of the Workgroup believed that the uncertainty surrounding what the HVDC expansion factor would actually be (which would not be known until the actual costs of each HVDC link is confirmed) could create significant uncertainty in TNUoS charges for prospective new generation connectees. Such cost information (on which the expansion factor is based) may not be available until close to the delivery of each HVDC link. This could make it difficult for prospective generation connectees to commit to their project and underwrite the transmission connection, which could in turn sterilise development relying on these connections. An example was given regarding the recent experience in the Western Isles where there has been a 60% increase in the estimated costs of a proposed HVDC link. Some Workgroup members felt that it would be particularly difficult to manage after developers have placed User commitment, secured finance and moved into the construction phase of their generation projects.

5.51 A potential alternative was suggested for the System Operator to estimate and fix the expansion factor for the HVDC link at T-4 (i.e. four years prior to commissioning of the link). It was felt that this would align with wider User commitment arrangements and TO commitments to transmission infrastructure. Under this potential alternative, the fixing would include the costs of physical transmission assets and include sharing factors and fixed cost deductions agreed elsewhere in CMP213 Original. It would also include a proportion of the estimated installation costs. Any subsequent changes to the cost (up or down) of an HVDC link therefore would be socialised within the TNUoS charging methodology, if passed through in the TO revenue stream. Any TO cost(s) above this initial fixed level would be socialised through the residual if deemed efficient (by Ofgem), and by the TO if deemed inefficient (by Ofgem). Cost reductions below the initial fixed level would similarly be shared by all Users, via the residual. A paper describing this potential alternative can be found in Annex 14.9.

5.52 The Workgroup discussed the merits of this potential alternative. The supporter of this potential alternative confirmed that the expansion factors would be derived four years prior to an HVDC link commissioning, based on the best available (to the SO) information at the time, and would not be altered if the HVDC link were delayed. It was acknowledged that the figure would be inflated by RPI annually.

5.53 Some of the Workgroup felt that this potential alternative may have possible regulatory implications as its treatment would be different to that of other expansion factors set at the start of each price control. It was also noted there may be consequential changes needed for the STC to provide National Grid, in its role as NETSO, with the required TO cost information.

5.54 At an initial vote on potential alternative elements, the majority of the Workgroup voted that this element (fix the HVDC expansion factor at T-4) should not be taken forward.

Summary of the HVDC elements taken forward into WACMs

5.55 Following the initial post-Workgroup consultation discussions, the Workgroup undertook a round of informal voting to consider which potential alternative elements should be taken forward into WACMs. In addition to the Proposer's Original of 100% of the converter station costs being incorporated into the calculation of the expansion factor, the HVDC related elements taken forward to be combined into WACMs were:-

- Remove 50% of the converter station costs based on elements similar to AC substations;
- Remove 60% of the converter station costs based on elements similar to AC substations and controllability similar to QBs; and
- Remove a specific percentage of the converter station costs based on elements similar to AC substations.

6 Summary of Workgroup Discussions on Islands

Introduction

6.1 The CMP213 Original seeks to develop a methodology for calculating cost reflective TNUoS charges for transmission spurs (connecting generation and demand) and comprised of transmission network technology not currently included in the expansion factors set out in paragraphs 14.15.47 and 14.15.49 of the (baseline) CUSC, such as those which may be established between the Scottish mainland and the Scottish islands of the Western Isles, Orkney and Shetland.

6.2 For transmission spurs, such as those connecting the Scottish islands, the Original proposes to calculate new expansion factors for each type of transmission network technology planned. Where such transmission circuits are comprised of HVDC technology, the methodology would be consistent with that proposed for HVDC transmission circuits paralleling the AC transmission network.

6.3 After the Workgroup consultation, the Proposer updated the CMP213 Original to alter the charging definition of a MITS node (see section 4.114-4.126) for the purposes of charging only. This has the effect of declassifying as MITS nodes those connected by a single radial circuit to the MITS. The consequence is that, with the initial connections currently proposed, transmission circuits connecting islands to the GB mainland would be classed as local. There was general agreement to this approach in the Workgroup. However, conceivably in the future, additional reinforcements could establish MITS nodes on the Scottish islands.

6.4 As the sharing aspect of the Original proposal assumes that sharing occurs implicitly across the wider transmission network, generators connected to nodes on islands classed as part of the MITS for TNUoS charging purposes would pay a two part tariff, including the sharing factor (based on their plant's annual load factor), associated with this aspect of the Original proposal.

6.5 Currently, in line with the design standards laid out in the NETS SQSS, it is not assumed that sharing occurs on transmission circuits classed as local. However, noting the work previously presented to the Workgroup by Heriot-Watt University and the impact that this could have on future transmission design considerations of counter-correlation of differing renewable generation technologies, a Counter Correlation Factor has been included in the Original proposal following the Workgroup consultation (see 4.105-4.113). The Proposer believed that this, in combination with the aforementioned change to the charging definition of MITS node, would suitably reflect any sharing of renewable generation technologies accounted for by a TO in the design of island transmission links.

Summary of Workgroup and consultation discussions to date

6.6 This section of the report is intended as a summary of discussions to date. Workgroup discussions after the Workgroup consultation can be found in this section, referencing the pre-Workgroup consultation discussions and Workgroup consultation responses where applicable. Further details of the Workgroup debate prior to the Workgroup consultation can be found in Annex 6 and the Workgroup consultation responses in Volume 3.

6.7 The Workgroup were asked to report on the following specific issues by the CUSC Panel as part of their Terms of Reference, which were in line with / in addition to those set out in the Authority's SCR Direction (appropriate report paragraphs from Workgroup discussions referenced):

h) ensure that the charging solution is commensurate with transmission access rights (whole of this section);
i) consider appropriate approach for islands that form part of integrated offshore networks (6.55); and
j) review the application of the expansion factor in the tariff calculation (6.23-6.50).

Initial Scoping of the Original proposal

6.8 Prior to the Workgroup Consultation, the Workgroup agreed the areas to be considered for the islands aspect of the CMP213 Original proposal could be summarised as:

Considerations from the Direction	Potentials changes to Original
a) Whether islands classed as 'wider' for charging purposes should have a 2 part wider TNUoS tariff as determined by the sharing aspect of the Original proposal	i) Islands classed as wider do not have a two part TNUoS tariff
b) Whether islands classed as 'local' for charging purposes should have TNUoS tariffs consistent with the current existing methodology for local circuit and local substation tariffs	i) Review local/wider definitions and perhaps consider an alteration/addition to accommodate Scottish islands (e.g. look at MITS)
	ii) Apply sharing to local circuits incl. Scottish islands
c) Whether the expansion factor should be calculated in a generic manner across all islands or whether it should be island link specific	i) Across all islands regardless of transmission technology
	ii) One generic factor for AC, and one for DC
	iii) Island (i.e. not link) or island group[9] specific
d) Whether, for islands classed as 'wider', the global locational security factor should be used without further modification or whether any lack of redundancy should be reflected in the expansion factor calculation	i) Yes; apply 1.8 for two circuit cases
	ii) Yes; some other factor between 1 and 1.8
e) Whether the expansion factor calculation for radial island links comprising HVDC technology should be the same as that for HVDC links that parallel the (onshore) AC transmission network	i) Yes (on all elements of HVDC options)
f) Whether an anticipatory application of the MITS definition to islands is appropriate and how this could be done.	i) Yes; just to islands
	ii) Yes; to everything

Table 20 – Areas to be considered for the islands aspect of the Original proposal

[9] 'Island Groups', for the purposes of Workgroup discussions were considered to be those in Scotland, and in particular (i) the Western Isles (ii) Orkney and (iii) Shetland only.

6.9 Given the extensive nature of the Authority's SCR Direction in this area, the Workgroup could not think of any further areas where the Original could be developed further that had not already been highlighted by the Direction or where any additional potential alternatives might be developed.

Discussion on the Original proposal and Potential Alternatives

6.10 This section covers the Workgroup discussions on each of the individual issues above. It does so by taking each of the six main considerations from the SCR Direction in turn, with each of the potential changes to the Original covered under these main considerations.

a) Whether islands classed as 'wider' for charging purposes should have a 2 part wider tariff as determined by the sharing aspect of the proposal

6.11 The Original proposal applies the principles of sharing set out within it to all parts of the transmission network considered to be part of the Main Interconnected Transmission System (MITS); i.e. 'wider'; for TNUoS charging purposes. Implicitly this would also include island transmission connections that are classed as 'wider'.

6.12 There was concern from the Proposer and some Workgroup members specifically around radial transmission circuits for islands connecting to the MITS and their classification as wider rather than local. This is because under the Original proposal, a sharing factor based on a generator's annual load factor (ALF) is applied to the wider element of the tariff as a proxy for its impact on incremental constraint costs. The Workgroup had discussed how this relationship deteriorated as the amount of low carbon generation increased behind a system boundary (see 4.16). The Workgroup considered that on islands, future developments are likely to result in high ratios of low carbon to carbon generation. Under the Original, some Workgroup members felt that using a generator ALF would lead to a reduction in cost-reflectivity in such situations. This would also be exacerbated by the high unit costs of cables connecting this generation to the GB mainland. It was argued that this effect could stretch the generic assumption of an ALF-based sharing factor in the Original so far as to make the Original proposal less cost-reflective than the baseline.

6.13 Under the three diversity method alternatives, this would be naturally taken into account and there was broad agreement that this effect would not be an issue for all the diversity alternatives.

6.14 Prior to the Workgroup consultation, the Workgroup discussed whether one solution to this issue would be to remove the two part element of the tariff for islands.

6.15 Following the Workgroup consultation, the Proposer proposed a change to the charging definition of the MITS in the CMP213 Original to change the local/wider definition so that radial transmission circuits would not, for the purposes of charging, be part of the MITS. This definition would class single sub-sea island transmission connections as local, and would also be applied to other onshore radial transmission circuitry, thus negating the issue identified under this element of the Authority's SCR Direction. The Proposer believed that this would address concerns raised prior to the Workgroup consultation, and there was general Workgroup agreement to this approach. Full discussions on this change of definition can be found in 4.114-4.126.

6.16 It was proposed that this definitional change was not required under all three potential diversity alternatives for the reasons stated in paragraph 6.13.

b) Whether islands classed as 'local' for charging purposes should have tariffs consistent with the current existing methodology for local circuit and local substation tariffs

6.17 Currently, for generation Users, the locational element of the TNUoS tariff is comprised of three separate components; (i) a wider component that reflects the costs of the wider transmission network (comprised of MITS nodes), and the combination of (ii) a local substation and (iii) a local circuit component that reflect the costs of the local transmission network.

6.18 Prior to the Workgroup consultation, the Workgroup considered that there were three possible approaches to incorporate islands into the TNUoS charging methodology in an efficient way:

i) Utilise the unique characteristics of island transmission connections to exclude island substations forming part of the MITS, such that all island transmission links would form part of a local circuit tariff and only the issues associated with this would have to be addressed;

ii) Utilise the unique characteristics of island transmission connections to include island substations as part of the MITS, such that all island transmission links would form part of the wider TNUoS tariff and only the issues associated with this would have to be addressed; and

iii) Maintain the existing definitions of local and wider and address the issues that arise for each category.

6.19 The pros and cons of these three approaches and the associated Workgroup discussions can be found in Annex 6, 6.43-6.52.

6.20 Prior to the Workgroup consultation, the Workgroup considered that there did not appear to be any justification to altering the definition of local and wider and maintaining an outcome where some island transmission links form part of a local circuit TNUoS tariff and others the wider TNUoS tariff.

6.21 Some in the Workgroup believed that the unique cost and configuration characteristics of island transmission connections were closer to that of local, rather than wider, circuits from the perspective of incremental transmission network costs.

6.22 Following the Workgroup consultation, the Proposer proposed a change to the definition of the MITS (for charging purposes only) in the Original to change the local/wider definition to go deeper into the transmission network, so that radial transmission circuits would not be part of the MITS. This definition would class single sub-sea island transmission connections as local, and would also be applied to other onshore radial circuitry, thus negating the issue identified under this element of the Authority's SCR Direction. Full discussions on this change of definition can be found in 4.114-4.126.

c) Whether the expansion factor should be calculated in a generic manner across all islands or whether it should be island link specific

6.23 The Original proposal would calculate a specific expansion factor for each island transmission circuit connection on the basis that the transmission technologies and hence unit costs could vary greatly across each connection. In addition, where HVDC transmission circuits are used the converter station costs are included in the expansion factor calculation, and hence circuit specific expansion factors would be necessary in order to maintain cost reflectivity.

6.24 Prior to the Workgroup consultation, the Workgroup discussed the pros and cons of generic vs. specific expansion factors for islands, and ways in which these could be derived (Annex 6, 6.55-6.70). Those in support of generic options felt they provide enhanced stability and predictability. However, others argued that using generic factors would reduce cost-reflectivity.

6.25 Following the Workgroup consultation, generic expansion factors for islands were not taken forward.

d) Whether, for islands classed as 'wider', the global locational security factor should be used without further modification or whether any lack of redundancy should be reflected in the expansion factor calculation

6.26 In the baseline charging methodology, the security factor for circuits classed as "wider" in the transmission network is 1.8. This is multiplied by the zonal location tariff for generators to reflect redundancy in the transmission system. However, as many island connection transmission designs are radial spurs and therefore are connected by a single radial circuit to the mainland, there is effectively no redundancy in the transmission circuit. Prior to the Workgroup consultation, the CMP213 Original therefore proposed to compensate for this in the charging methodology by adjusting the length of any portion of an island link with no redundancy in the Transport Model by multiplying its actual length by 1/(Locational Security Factor). The result would be that when the TNUoS tariff was later multiplied by the locational (MITS) security factor (currently 1.8) this would cancel out and only be reflected as a single transmission circuit in the TNUoS tariff; i.e. it would result in an island security factor of 1.0, rather than 1.8.

6.27 Some potential alternatives to this option were discussed by the Workgroup. Some of the Workgroup believed that it was not appropriate for 1.8 to be applied to islands classified as "wider". Some Workgroup members felt that applying a factor between 1.0 and 1.8 depending on the redundancy of the transmission circuit may be more appropriate, and would be in line with those circuits classed as "local".

6.28 After the Workgroup consultation, the CMP213 Original was amended (by the Proposer) in respect of the MTIS definition of "local" and "wider" which would mean island connections are now classed as local. This would therefore apply a factor of either 1.0 or 1.8 to island transmission connections, depending on the level of redundancy. This would also negate the need to reduce the security factor of wider island transmission circuits under the CMP213 Original.

6.29 However, it was noted that the requirement for this security factor of 1.0 would still be required for all three diversity alternatives, where the proposed change to the definition of MITS would not be made.

e) Whether the expansion factor calculation for radial island links comprising HVDC technology should be the same as that for HVDC links that parallel the AC network

6.30 The Original proposal would calculate the expansion factor for HVDC island transmission links in the same manner as for those that parallel the AC transmission network.

6.31 As part of the Original proposal all converter station costs are included in the calculation of the HVDC transmission circuit expansion factor.

6.32 The Workgroup investigated some potential alternatives to this approach.

Remove all converter station costs from the calculation

6.33 The Workgroup considered whether this would be the case for all aspects of HVDC TNUoS charging as discussed in Section 5, above.

6.34 The Workgroup agreed that, due to the radial nature of the proposed island HVDC transmission links, the calculation of impedance for these links, as is necessary when they parallel the AC transmission network, is not required.

6.35 In terms of the calculation of the expansion factor for HVDC transmission links, the Workgroup considered complete removal and partial removal of the converter station costs from the expansion factor calculation as well as treating HVDC as onshore in Section 5.

6.36 The justification for the complete removal of the converter station costs was on the basis that these elements constitute a fixed cost and hence have an overall negative effect on cost reflectivity. Whilst this was disputed by some of the Workgroup, this justification would also apply to island HVDC links and therefore for this potential alternative the calculation should remain the same.

6.37 The interaction and potential read across to offshore transmission circuits where HVDC converter station costs are included in the expansion factor calculation was noted by the Workgroup. Some believed that this inconsistency was not acceptable and that converter station costs would also have to be removed from the offshore TNUoS calculation in this case.

6.38 Some in the Workgroup also noted that, unlike offshore transmission circuits, the island links did include demand Users and, furthermore, islands are not considered to be offshore as they are part of the (onshore) TO's Transmission Licence area (and are not part of an OFTO's Transmission Licence area). These members believed that these reasons alone were sufficient to warrant a different treatment of HVDC converter station costs when calculating TNUoS between islands and offshore.

Remove some converter station costs from the calculation

6.39 The Workgroup also identified two possible alternatives for the removal of a portion of the converter station costs from the expansion factor calculation:

i) Remove a ***generic*** percentage of the costs based on those elements of the converter station that are similar to elements of the AC transmission network that are currently not included in the locational signal (such as substation equipment); and/or

ii) Remove a portion of the costs based on the benefit to the transmission network arising from the operation of HVDC technology. This is particularly relevant to voltage source converters (VSC), which will be used for island links, which can be beneficial to system performance and can provide overall a more effective solution than traditional HVAC.

6.40 Post-Workgroup consultation, the following options were also discussed:

iii) Remove a ***specific*** percentage of the costs based on those elements of the converter station that are similar to elements of the AC transmission network that are currently not included in the locational signal (such as substation equipment)

i) Remove a ***generic*** percentage of the costs based on those elements of the converter station that are similar to elements of the AC transmission network that are currently not included in the locational signal (such as substation equipment);

6.41 This option was devised for incorporating HVDC transmission circuits that parallel the AC network (see 5.24-5.28). The Workgroup noted that this justification would also apply for radial island HVDC transmission circuits. However, as with the potential alternative removing 100% of the converter station costs from the expansion factor calculation, some in the Workgroup believed that the logic for applying this option could also be read across to the existing TNUoS charging methodology with respect to offshore (OFTO) transmission.

6.42 Nevertheless, some of the Workgroup believe that offshore transmission should not be used as a precedent to determine the charging structure for island links. Whilst there are some similarities there are also important commercial and technical differences between the two types of transmission connection:

- Specific commercial arrangements have been put in place to help facilitate the development of offshore wind technology, including levels of policy support and the OFTO arrangements in respect of transmission connections. Offshore connections tend to be radial links to individual generator stations.
- Island transmission links are part of the onshore TO's Transmission Licence area and are not part of an OFTO's Transmission Licence. The island links will connect multiple generator stations covering different technologies as well as meet the needs of demand on the island. 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 demand side growth, and relieving reliance on local carbon standby generation. A Workgroup member also argued that the links to certain islands will also relieve congestion on other sections of the transmission network, although there was no evidence produced to support this supposition.

ii) Remove a portion of costs based on the benefit to the transmission network arising from the operation of HVDC technology. This is particularly relevant to voltage source converters (VSC), which will be used for island links, which can be beneficial to system performance and can provide overall a more effective solution than traditional HVAC**.**

6.43 This option recognises the benefits arising from the VSC converter technology. A paper was circulated to the Workgroup following the Workgroup consultation regarding the benefits of this transmission technology, and can be found in Annex 14.6. This paper argued that VSC based HVDC transmission technology can, in the right circumstances, offer benefits over traditional HVAC transmission Technology because VSC converter stations not only enable efficient long distance power transmission, but also provide very controllable reactive compensation capability, which will benefit both the embedded network to which it is connected and the quality of supplies for demand at the remote end.

6.44 It was argued that, in the case of island transmission links, HVDC based on VSC technology can provide a better solution than traditional HVAC, taking into account technical capability, cost and environmental impact. Following the Workgroup consultation, evidence was presented to the Workgroup to suggest that an appropriate proportion to remove from island HVDC converter station costs for VSC benefits was 20%.

6.45 Some Workgroup members, whilst acknowledging the benefits of VSC transmission technology, questioned whether it was needed to benefit the transmission system or a "nice to have", and if the latter, whether removing a portion of the costs on that basis was appropriate.

6.46 The Workgroup voted on whether this 20% proportion (related to VSC transmission technology benefits) of island HVDC converter station costs should be removed, and there was not majority support for this option. However, the Chair of the Workgroup confirmed this element should be carried forward for consideration as a potential alternative on the basis they believed sufficient evidence had been presented for it to be considered by Ofgem.

<u>iii) Remove a ***specific*** percentage of the costs based on those elements of the converter station that are similar to elements of the AC transmission network that are currently not included in the locational signal (such as substation equipment)</u>

6.47 As in Section 5, a potential alternative on this was raised by a Workgroup member. Full discussions around this potential alternative can be found in 5.34-5.36.

<u>Fix HVDC expansion factors at T-4</u>

6.48 As in Section 5, a potential alternative was raised by a Workgroup member to fix the HVDC expansion factors, for island transmission links, at T-4. Full discussions around this potential alternative can be found in 5.50-5.54.

6.49 It noted that by fixing a sharing factor at T-4, the potential for future beneficial sharing to be recognised would be lost.

6.50 At an initial vote on potential alternative elements, the majority of the Workgroup voted that this element should not be taken forward.

f) Whether an anticipatory application of the MITS definition to islands is appropriate and how this could be done.

6.51 Prior to the Workgroup consultation, the Workgroup discussed an option whereby the existing definition of a MITS node would be applied (in advance of it actually occurring) to an island transmission link (for the purposes of TNUoS charging) where it was reasonably 'anticipated', by the SO, that such a MITS node would exist at some point in the future (Annex 6, 6.100-6.113).

6.52 It was decided prior to the Workgroup consultation that if this was taken forward, it would be applicable to the whole transmission system, as applying this only to islands could be seen as discriminatory.

6.53 Some respondents to the Workgroup consultation felt it was not appropriate to charge on the basis of anticipating changes to generation backgrounds, that this option would be overly problematic, and that the risks would outweigh the benefits.

6.54 Following the Workgroup consultation, it was decided that this would not be taken forward as a potential alternative.

Other issues covered

6.55 The Workgroup discussed the potential for an offshore hub in relation to the CUSC Panel Terms of Reference item i. One member of the Workgroup representing islands updated the Workgroup that the latest plans associated with island connections was not for an offshore hub but an onshore hub, and therefore the issue no longer existed. The Workgroup discussed that this was an area more appropriate to be taken forward in a future modification for integrated offshore on the basis that there were no plans that directly affected islands.

Summary of elements taken forward into WACMs

6.56 Following the initial post-Workgroup consultation discussions, the Workgroup undertook a round of informal voting to consider which potential alternative elements should be taken forward into WACMs. The islands related elements taken forward to be combined into WACMs were:

- Remove 50% of the converter station costs based on elements similar to AC substations;
- Remove 70% of the converter station costs based on elements similar to AC substations and VSC converters; and
- Remove specific percentage of converter station costs based on elements similar to AC substations.

7 Impact Assessment Modelling

7.1 This section describes the impact assessment modelling undertaken by National Grid to provide a robust evidence base for the Original and potential alternatives raised under CMP213.

7.2 Full Stage 2 results of the impact assessment are provided in Annex 15.

Background

7.3 As part of the transmission charging Significant Code Review under Project TransmiT (see Annex 7), a range of potential charging options were considered and assessed to understand which would best further the objectives of achieving sustainability targets, ensuring security of supply and providing best value for money for current and future consumers.

7.4 Redpoint Energy were commissioned by Ofgem to provide a quantitative assessment of how the different charging options might impact on these objectives. That assessment was completed using a suite of models developed by Redpoint Energy with assistance from National Grid. Redpoint Energy provided a report of the results of this assessment, along with the methodology and assumptions made in December 2011[10].

7.5 The Direction issued by the Authority to National Grid in relation to the Significant Code Review under Project TransmiT required National Grid to ensure that any Modification proposals developed were supported by a robust evidence base.[11]

7.6 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.

7.7 The functionality and approach to the analysis remains unchanged from that developed by Redpoint for this earlier analysis and is described in full in their report of December 2011.[12]

7.8 In order to ensure the information and assumptions used within the model remained current, the CMP213 Workgroup established a modelling sub-group to review this area of work. As a result, National Grid, through this discussion with the modelling subgroup, has reviewed the Redpoint model and has updated several data sources to better reflect the current background assumptions. These changes are listed in Table 21 below and were shared with the full Workgroup. Additionally RPI increases have been made as required with results given in 2012/13 prices.

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[10] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

[11] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20direction%2025%20May%202012.pdf

[12] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Modelling%20the%20impact%20of%20transmission%20charging%20options.pdf

Area	Change
Sustainability	Levy Control Framework 2020/21 target spend
Commodity Prices	Updated in line with DECC 2012 Energy and Emissions Projections[13]
Carbon prices	Updated in line with DECC's forecasts published in the Updated short-term traded carbon values for modelling purposes[14] document
Electricity Demand	Demand assumptions are based upon National Grid 2012 Gone Green scenario, as published in the National Grid 2012 Ten Year Statement[15].
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. Beyond, Redpoint data compared with both the contracted background and that assumed in National Grid's accelerated growth scenario[16].
Generation Life Expectancy	No change apart from existing nuclear fleet following review with Workgroup.
Generation Capital and Operational Cost Information	Capital and non-use of system operating cost information has been updated for conventional[17] and non-marine based renewables[18] based upon recent studies commissioned by DECC.
Transmission Reinforcements	Final RIIO proposals for each TO. National Grid Ten Year Statement
Island sub-sea links	2011 ODIS and discussions with SHE-Transmission
Allowed Transmission	Updated for final RIIO-T1 proposals

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[13] https://www.gov.uk/government/publications/2012-energy-and-emissions-projections....

[14] 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)

[15] 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/).

[16] 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/).

[17] For conventional plant the majority of data was taken from: Electricity Generation Cost Model – 2012 Update of Non Renwable 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).

[18] 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).

Area	Change
revenues	
Transport Model Assumptions	Updated to 2013/14 values with exception of generation charging zones (expansion constant converted to 2012/13 prices).
G/D split	27:73 split maintained

Table 21 - Table of Modelling Updates Made

7.9 The Workgroup agreed that the impact assessment should be carried out on six models representative of potential future scenarios. These models are set out in Table 22 below, and the Workgroup believed provided sufficient representation to allow their assessment to provide a robust evidence base.

Model	Sharing Assumptions	Islands / HVDC Assumptions
Status Quo	None	100% of converter costs included
Original	Original	100% of converter costs included
Diversity 1	Diversity 1	100% of converter costs included
Diversity 2	Diversity 2	100% of converter costs included
Diversity 3	Diversity 3	100% of converter costs included
HVDC – 50%	Original	50% of converter costs included

Table 22 -Table of models assessed

7.10 In line with the work previously carried out by Redpoint, two stages of analysis were undertaken. A first stage with fixed Contract for Difference (CFD) strike prices, and a second where CFD strike prices were altered to ensure three conditions were met;

- EU renewable share at 2020 of 30% (tolerance of +3%[19])
- Carbon emissions in 2030 at 100g/kWhr (+/- 7%)
- Nuclear capacity at 2030 of 14GW (+/- 7%)

7.11 As these Stage 2 results changed strike prices to ensure that renewable and emissions targets were met, the Workgroup accepted that consideration of the impact on Greenhouse Gas emissions would be through consideration of the impact on the average consumer bill.

7.12 The Workgroup requested Stage 2 results ahead of the determination and voting on the WACMs, as there was general agreement that this assessment would provide an evidence base to better inform the voting decisions of Workgroup members against the Applicable CUSC Objectives.

7.13 The Proposer, as National Grid representative, presented these findings to a Workgroup meeting. A summary of the discussions is recorded below. The full results of the Stage 2 analysis are provided in Annex 15.

Summary of Workgroup Discussions

7.14 The Stage 2 impact assessment modelling results were presented to the Workgroup at the meeting of 13th March 2013. This section summarises initial comments received, although there was general agreement that it was difficult to provide a full critique with only graphical information and little time for Workgroup members to analyse the information. National Grid

[19] For the avoidance of doubt, the tolerance is only plus %, not plus or minus % as per the other two conditions.

subsequently provided WG members with all data outputs from the Stage 2 impact assessment modelling to ensure this full assessment could be made prior to Workgroup voting. This Stage 2 data output will be made available by National Grid, on request, as part of the Code Administrator consultation with full details being provided in Annex 15.

7.15 There were general comments on some observable trends. The presenter noted that renewable generation targets for 2020 and 2030 emissions targets were all met due to the nature of Stage 2 modelling, and that their impact needed to be assessed through consideration of future consumer bills. It was noted that transmission investment was similar for all six model results, with earlier builds (presumably HVDC links) in the HVDC – 50% option. It was also noted that Diversity method 2 led to more renewable generation in the 2020s.

7.16 Other charts had less discernable trends. This included the impact on consumer bills where there was little consistency between years, and also transmission losses (although this was noted to be a cost chart rather than a volume chart).

7.17 There were comments on the use of 2012/13 generation charging zones. Some Workgroup members felt that the results could be better presented on a nodal basis as zones could change considerably in the period to 2030. The presenter commented that any zones used were likely to be illustrative, and therefore it was not significant which zones were used, as results were only for comparative purposes between the six models.

CUSC Panel discussion on the Workgroup report

7.18 The CUSC Panel noted that in 2024 there appeared to be an anomaly in the modelled tariffs. This reflects the discussion by the Workgroup (paragraph 1.68). National Grid indicated that as part of its work following the formal Workgroup process, it would investigate this further and intends to publish a refined industry impact assessment in response to the Code Administrator consultation. However, at this stage, National Grid believed the broad outcome and trends between models to be robust. Aside from the concern regarding 2024, results are believed to have an acceptable level of accuracy considering the broader assumptions. It was further noted that modelling uncertainty will always increase over longer time horizons. The models are intended to illustrate the longer term broader industry impact of the proposals and therefore would not change the proposals themselves.

8 Impacts

Impact on the CUSC

8.1 CMP213 requires amendments to the following parts of the CUSC:

i. Section 14 – Charging

ii. Section 11 – Interpretation and Definitions

8.2 CMP213 represents a significant incremental change to the TNUoS charging methodology. As such, substantial redrafting of Section 14 of the CUSC relating to Charging Methodologies will be required. In particular those sections relating to TNUoS and associated examples (paragraphs 14.14 – 14.28) will need to be overhauled. In addition, as noted under paragraphs 4.165-4.166, there is likely to be consequential changes required to the CUSC if CMP213 is implemented, with respect to STTEC and LDTEC, given that both are linked to TNUoS charges (which would be altered, if CMP213 was implemented).

8.3 This substantial change is made more complex due to the fact that CMP213 focuses on three different areas of change to Section 14. The summary below demonstrates the broad changes required for each topic area:

Sharing

8.4 Substantial updates would be required to paragraphs 14.14-14.28 to incorporate the move to a sharing approach. For example, should the Original proposal be taken forward, the approach, in the charging methodology, around the use of the dual background (Peak Security and Year Round elements) would need to be demonstrated as well as calculation of the generator's Annual Load Factor, inclusion of a generation plant type scalar for the Peak Security element and additional tariff assumptions would need to be included.

HVDC

8.5 A methodology has been developed for taking account of HVDC transmission circuits that parallel the AC network within the calculations of the Transport Model. For the Original proposal this would mean treating HVDC circuits as a pseudo-AC transmission circuit. Therefore a new part of Section 14 would be required to detail the methodology for determining the 'impedance' of these HVDC transmission circuits. In addition, new expansion factors would need to be added.

Islands

8.6 A methodology has been developed for calculating cost reflective TNUoS charges for transmission spurs connecting generation and demand and comprised of transmission network technology not included in the expansion factors set out in clause 14.15.47 and 14.15.49 of the CUSC (i.e. sub-sea cables); such as those which may be established between the Scottish mainland and the Scottish islands of the Western Isles, Orkney and Shetland. Whilst many aspects of island connections are covered under the other two aspects of CMP213, there will be additional items that are island specific which will need to be reflected into the charging methodology.

8.7 The full details of the actual impact on the CUSC arising from CMP213 (Original and WACMs) is shown in the Legal Text for the Original and each WACM in Volume 4.

Impact on Greenhouse Gas Emissions

8.8 As some of the options being considered under CMP213 will affect decisions about where to open new generation plant and where to close existing plant, the Panel agreed that CMP213 will have a material impact on Greenhouse Gas emissions and has tasked the Workgroup with considering this.

8.9 The Workgroup discharged this task as part of the Impact Assessment Modelling, outlined in Section 7, which included a specific assessment of the greenhouse gas emission impacts of the six options modelled. The Workgroup believed that through the modelling of these six options, as described in paragraph 7.9, the impact on greenhouse gas emissions of all potential Workgroup alternatives could be understood.

8.10 Stage two modelling of the National Grid Impact Assessment has renewable support mechanisms adjusted for each model to ensure targets are met, therefore any greenhouse gas emission impact needs to be considered through the impact on consumer bills. These are shown in Chart A15.25 of Annex 15 for all six models studied, and repeated below for convenience.

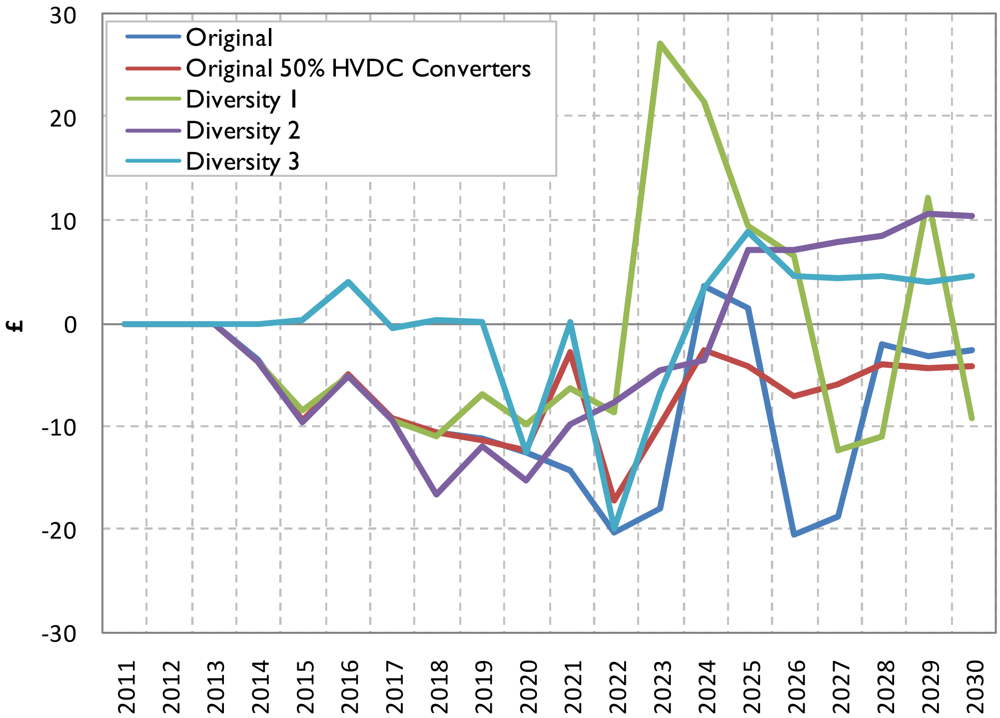

Figure 23 – Change in average consumer bill from status quo

8.11 It should be noted that, in addition to renewable support mechanisms, there are other variables that impact on these results, including the wholesale price of energy.

Impact on Core Industry Documents

8.12 Neither the Proposer nor the Workgroup have identified any impacts on Core Industry Documents at this stage, although the Workgroup noted that some consequential changes to the STC might be necessary in the future.

Impact on other Industry Documents

8.13 Neither the Proposer nor the Workgroup have identified any impacts on other Industry Documents at this stage.

9 Proposed Implementation

Background

9.1 The implementation date of CUSC Modification Proposals is ultimately decided by the Authority when approving a CUSC change. However, the Workgroup and the CUSC Panel have a role in providing advice and evidence to Ofgem on potential implementation dates.

9.2 The Workgroup discussed the various statements by Ofgem on the need to implement any Project Transmit change to TNUoS charging in a timely, but robust manner. The Authority Direction issued to National Grid stated in the covering letter[20], 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."

9.3 The Workgroup also considered the need for any transition arrangements associated with CMP213. These would normally recognise that any significant change to commercial arrangements should be implemented in a manner which allows industry parties time to efficiently adapt to such changes.

9.4 During the Workgroup consultation, stakeholders were asked for their views on potential implementation date and transition options, which were fed into post-consultation discussions by the Workgroup and its implementation subgroup.

Impact on Users

9.5 In terms of the impact on Users, the CMP213 Workgroup noted that any change to TNUoS tariffs should only directly impact on the allocation of TNUoS between individual generators. However, some members noted that there could be an impact on demand as generation reacts to the changed signals, either in the strength of the locational signals or changes to transmission investments and therefore the absolute level of transmission costs may change, of which demand Users pay 73% directly.

Timeline and resourcing issues

9.6 Having reviewed the timeline, the Workgroup considers that the earliest the Authority could, practically, make a decision on CMP213 Original and any WACM(s) is approximately September 2013. This leaves just sufficient time to allow National Grid to produce draft 'indicative' TNUoS tariffs in December (2013), with the final tariffs being produced by the end of January (2014).

9.7 Some Workgroup members noted that there could be a strong argument, in this particular case, for the Authority to authorise National Grid (if necessary) to undertake preparatory work on the final generation TNUoS tariffs prior to an Authority decision.

9.8 If this 'pre-approval' work were to be undertaken then it would feasibly be possible for National Grid to produce final TNUoS tariffs (as they did with the 2010 'mid year' TNUoS tariff change) earlier than January 2014 (assuming an Authority decision in September 2013).

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

9.9 Other Workgroup members commented that any sort of ‘pre-approval’ work would need to be done in a transparent manner, given the breadth of the changes proposed by CMP213, and the practicalities of such a process if a large number of WACMs were to exist.

9.10 It was also noted by the Workgroup that as part of the Final Modification Report to be submitted by the CUSC Panel to the Authority (anticipated to be in spring 2013), the analysis presented would include illustrative TNUoS tariffs and therefore Users would have a relatively up-to-date forecast of TNUoS charges if CMP213 (Original and any WACM(s)) was approved. However, it was noted that this information would not cover all potential WACMs and would reflect 2012/13 generation charging zones.

9.11 National Grid is currently reviewing the full impact on its IS systems of the changes associated with CMP213. National Grid also noted that parallel production of TNUoS tariffs under the different options being considered would be resource intensive and that this resource is specialised in nature. Therefore it is unlikely that TNUoS tariffs could, practically, be developed for all the options currently being considered by the Workgroup.

9.12 There was general Workgroup agreement that Users would require, under the Original Proposal, a period of time to validate ALFs produced by National Grid and comment back prior to the production of final tariffs for a charging year at the end of January t-1. However, there was no agreement over a suitable period with some of the Workgroup believing 10 Working Days was sufficient, whilst others preferring a duration of 30 Working Days. The National Grid representative believed it was sufficient, given the small expected number of challenges, that ALFs were produced in line with the publication of draft TNUoS charges in December of t-1, with any validation being completed in time for the publication of final tariffs in the following January.

9.13 With regards to the hybrid option, in addition to the comments noted on the Original regarding User confirmation of National Grid produced ALFs, there was general Workgroup agreement that a period of 30 Working Days would be required to enable Users to consider the National Grid produced ALF and decide to submit their own User forecast. The National Grid representative believed that this could have a significantly larger impact on the TNUoS charge setting process, and considered that any User forecasts should be submitted ahead of the publication of draft tariffs in December of t-1. On this basis, the National Grid representative considered that National Grid ALFs should be provided to users by the end of October of t-1, as this would allow sufficient time for users to submit their own forecasts and for National Grid to update their charging models accordingly. Where the Authority decision is after 1st October for an implementation in the following April National Grid would follow the process outlined in 9.12 for the first year of implementation, i.e. the user forecast option would not be available until the first full charging year. It was also noted that there would be IS changes required to enable reconciliation of the hybrid ALF, although National Grid expected that these could be completed up to a year after implementation. These would be in addition to any IS changes required to support the Original.

Implementation dates

9.14 At the Workgroup Consultation stage, four possible target implementation dates were considered, along with the Workgroup’s views on the potential benefits and dis-benefits of each of these:

Option 1) ‘mid year’ during the 2013/2014 TNUoS Charging Year; or

Option 2) 1st April 2014; or

Option 3) ‘mid year’ during the 2014/2015 TNUoS Charging Year; or

Option 4) 1st April 2015.

Options 1 and 3 – 'Mid year' changes

9.15 In respect of option 1 ('mid year') the CMP213 Workgroup was mindful that this did not necessarily mean exactly midway or halfway through the 2013/14 Charging Year; i.e. 1st October 2013 (or 1st October 2014 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 tariff change and this had actually been put into effect on 1st December (2010)[21].

9.16 Prior to the Workgroup consultation, the Workgroup noted that the Project Transmit Technical Working Group[22] had considered, and discounted, a 'mid year' TNUoS tariff change, although this had included a 'postage stamp' option, which is specifically excluded from CMP213.

9.17 With respect to options 1 and 3, many Workgroup consultation respondents felt that 1st April implementation dates were preferable to those that fell mid-charging year, with only two respondents supporting a 'mid year' change option. This view was echoed by the majority of the Workgroup both pre and post-consultation.

9.18 'Mid year' changes are not favoured by parties as planning for TNUoS changes currently take place based on 1st April each year. 'Mid year' changes are seen as creating tariff volatility. In addition, 'mid year' changes are not favoured by National Grid as they are resource intensive and involve multiple tariff setting and complex reconciliation processes. To exacerbate this, a large scale methodology change such as proposed in CMP213 would be more complex than previous 'mid year' changes implemented which had only involved changing the residual for all Users.

9.19 However, some argued that a 'mid year' change was preferable if it were to avoid delay until a 1st April date, because a timely and expeditious introduction ensures that a fairer and more cost reflective allocation is achieved at the earliest practical opportunity. In respect of parties not having the indicative TNUoS tariffs, it was suggested that the illustrative tariffs in the Workgroup report could potentially inform Users. However, there was concern that the illustrative tariffs in the Workgroup report were quite diverse between options, and did not reflect the full suite of potential WACMs, and therefore these could not reasonably be used to inform commercial decisions. In terms of risk management most parties indicated that they were assuming 1st April 2014 implementation at the earliest, and so would ignore the potential risk that could be introduced by a 'mid year' change in charging year 2013/14.

9.20 Considering the balance of arguments above, the majority of the Workgroup concluded that 1st April 2014 or 1st April 2015 would be most appropriate as the implementation date for CMP213 (Original or WACM(s)), as opposed to mid-charging year.

Option 2 –1st April 2014

9.21 The CMP213 Workgroup noted that the Project Transmit Technical Working Group[23] favoured an implementation from 1st April 2014. However, some CMP213 Workgroup members and consultation respondents considered that

[21] http://www.nationalgrid.com/NR/rdonlyres/11407548-92EE-485B-9A1C-5DBFAAD17F42/43351/NoticeofFINALtariffs.pdf
[22] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=166&refer=Networks/Trans/PT/WF
[23] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=166&refer=Networks/Trans/PT/WF

given the potentially significant material impact on some Users that it would not be beneficial to implement from the 1st April 2014.

9.22 As with the 'mid year' options, it was argued by some Workgroup members, and a number of Workgroup consultation respondents, that an early implementation date ensured a fairer and more cost reflective charging methodology is achieved at the earliest practical opportunity, and would therefore benefit Users and consumers sooner.

9.23 Other supporters of an earlier implementation date argued that introducing changes sooner reduced uncertainty for all Users.

9.24 The main concern from a number of Workgroup members and Workgroup consultation respondents with the 1st April 2014 option was around the notice period for generation Users to be able to react to the amended cost signal. This included where generators have sold power on longer term contracts, the ability of demand Users to take account of potential TNUoS changes efficiently during the demand contracting rounds and User Commitment liabilities[24] prior to 1st April 2014. This would then create windfall gains and losses and therefore "winners" and "losers", which would undermine regulatory certainty.

9.25 A counter argument was posed that large scale changes to the charging methodology would always create "winners" and "losers" and that therefore this risk would have already been taken into account by Users in their strategic decision making. A further counter argument was that if the change improved cost reflectivity (of TNUoS charges) then any undue delay in implementation would equally create "winners" and "losers" the other way; as those who would 'lose' from the change would 'win' (in the short term) as a result of the delayed implementation, whilst those who would 'win' from the change would 'lose' (in the short term) as a result of the delayed implementation.

9.26 Some Workgroup members felt that in respect of the impact on demand Users, that the impact should be minimal as their charges from suppliers should be linked to the wholesale market price.

9.27 Similar to the issue for 'mid year' tariff changes, some Workgroup members felt the range of options in the report reduced the usefulness of the presented illustrative tariffs for making commercial decisions. However, some felt that as these illustrative generation TNUoS tariff would be provided as part of the CMP213 Final Modification Report submitted to the Authority as part of the assessment process in the spring of 2013, this would limit the potential uncertainty for Users.

9.28 In addition, as noted in paragraph 9.5, some Workgroup members believed there would only be a "minor impact on demand TNUoS as generation reacts to the changed signals" arising from the implementation of CMP213, whilst other members believed that the impacts on demand could potentially be very significant if there are generation changes in the higher demand areas.

9.29 The User Commitment interaction (noted in 9.24) is that during the normal course of events a User with generation assets has to provide notice (to reduce their TEC) to the System Operator (NGET) 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

[24] These can be found in section 15 of the CUSC [24]These can be found in section 15 of the CUSC

http://www.nationalgrid.com/NR/rdonlyres/2561685B-659F-4E6C-9CB8-AE74AEE582FD/52985/CUSCSection15v1031March2013.pdf cannot efficiently manage. Counter to this, parties argued that the range of generation TNUoS tariffs were available. However, it was noted that this range was quite large and therefore represented a large risk with limited opportunity to efficiently manage it. It was noted that the cancellation charge is no longer directly linked to TNUoS. It was also suggested that parties have wider contractual commitments that need to be considered. For example, with option 2, a generator would, if it wished to avoid paying TNUoS from 1st April 2014, need to notify National Grid of its TEC reduction (to zero MW if it wished to avoid the charge entirely) at least five Working Days prior to the 31st March 2013.Therefore, it was argued by some that, in order to be consistent with these arrangements, a 1st April 2014 implementation date was unworkable, and that transition arrangements may be required if this date was selected. Others argued that this was workable but introduced additional risk.

<u>Option 4 - 1st April 2015</u>

9.30 Some members of the CMP213 Workgroup and some Workgroup consultation respondents believed that the implementation of CMP213 should be made from 1st April 2015. This would allow Users to fully include the effect of CMP213, in wholesale prices and so promote confidence in the overall regulatory regime. It would also avoid interaction with notice periods under the User Commitment regime for existing Users.

9.31 Some argued however, that delaying implementation to 1st April 2015 may cause adverse commercial impacts for Users and consumers who would have benefitted from the signal being amended more quickly.

9.32 In addition, some Workgroup members believed; 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"*; and that the SCR started in September 2010[25] that it would be inappropriate to unduly delay the benefits associated with CMP213 (if approved by the Authority) by postponing the implementation of CMP213 until 1st April 2015.

9.33 The majority of the Workgroup and a number of Workgroup consultation respondents believed that if a 1st April 2015 implementation date was selected, transition arrangements would not be required.

9.34 Post Workgroup consultation, an option was discussed by the Workgroup whereby the "one year and five Working Day User Commitment notice period principle was retained through a codified delayed implementation, whereby the implementation date of the Modification Proposal would take place on April 1st at least one year and twenty working days (one year and 5 Working Days, plus fifteen Working Days for Users to assess the impact and submit their formal notice, of TEC reduction, to National Grid) after the Authority decision date.

9.35 This option had significant support within the Workgroup for the reasons highlighted in section 9.24 in support of a 1st April 2015 implementation. However, other members of the Workgroup felt that hard-coding this approach to implementation / transition was unnecessary as the Authority would be free to choose a 1st April 2015 implementation date should they wish to. It was argued that it should be sufficient to make the case to the Authority, in that the Authority would make the appropriate decision having considered all pros and cons.

9.36 Other Workgroup members felt that such an option could be seen as discriminatory to those who would have benefitted from an earlier

[25] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/PT

implementation of the proposals, such as at the next 1st April or 'mid year'. There was also concern that it would set a precedent for delaying other changes to the charging methodology in the future.

Transition

9.37 The Workgroup also considered the need for any transition arrangements associated with CMP213. These would normally recognise that any significant change to commercial arrangements should be implemented in a manner that allows industry parties time to efficiently adapt to such changes.

9.38 Transition arrangements are often also required where methodological changes would lead to significant commercial and operational changes. Some examples are: (i) to allow generation Users to adjust their transmission access rights without penalty; (ii) recognise that certain categories of User may need specific treatment (e.g. LCPD generation plant); (iii) to allow the development of supporting IS systems (e.g. implementation with temporary 'work-arounds' on existing systems); and (iv) to allow industry contracting arrangements (e.g. PPAs) to be amended.

9.39 In respect of the issue that transmission charging changes should be managed efficiently, the Workgroup noted 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, when Ofgem initiated its Project Transmit SCR work. However, it also recognised that there was a significant range of potential options and so there still remains a considerable amount of uncertainty.

9.40 It was also noted that any implementation option prior to 1st April 2015 would require transitional arrangements if a WACM with the hybrid ALF option was approved by the Authority. The Workgroup discussed that prior to this, Users would not submit a forecast for their ALF (i.e. for implementation on 1st April 2014 User submissions would not be available) – see paragraph 9.13.

9.41 A further area of concern was that should a User consider reacting to a change in their TNUoS tariff; e.g. by closing a station; there was insufficient liquidity in the energy markets to commercially manage the situation. Some members however, disputed this view noting that if there is insufficient liquidity in the energy market then presumably the generator has not sold their output forward, so the commercial impact is minimal

9.42 The majority of the Workgroup thought that transitional arrangements would only be necessary if an implementation date prior to 1st April 2015 was decided by the Authority.

<u>TEC reduction options</u>

9.43 Prior to the Workgroup consultation, the Workgroup considered a possible transition arrangement option. This would be where the CMP213 implementation date does not allow generation Users sufficient time to adjust their transmission access (TEC) holdings in response to the CMP213 change then a shorter than (i) one year and five Working Days notice period for existing generation plant; and (ii) three years and five Working Days notice period for new generation plant (as per the recently changes (with CMP192) to User Commitment liabilities).

9.44 Post the Workgroup consultation, two specific options were raised to take this into account:

(i) Full TEC reduction (existing TEC 100% to zero (MW) TEC) only;

and

(ii) A range of TEC reduction (from 100% to less than 100% including, but not limited to, zero (MW) TEC)

9.45 Both of these options would allow the User to reduce their TEC, stating explicitly that the reason for their reduction was due to the CMP213 TNUoS change. If they stay on the system for their notice period, they would then pay the wider locational tariff based on the existing (CUSC baseline) charging methodology inflated by RPI for the volume of reduced TEC for the equivalent determined User Commitment period for existing Users. Any under recovery arising from this would be paid by all generation Users in the generation residual. If they leave the system within the notice period, the CMP 192 cancellation charge would apply.

9.46 Some Workgroup members felt that this option was potentially discriminatory as it involved treating new Users differently to existing Users of the transmission system. It was noted that for new generation plant the lead time for User Commitment was up to 4 years. If exiting generation Users were able to avoid User Commitment it was not clear why new generation Users, whose projects may as a result of CMP213 become marginal or even no longer viable, should not be able to benefit from similar transitional arrangements; i.e. provide less than the current three years and five Working Days notice.

9.47 Some of the Workgroup also believed that the Full TEC reduction only option was more discriminatory, as it involved treating existing Users wishing to reduce TEC differently to those wishing to close.

9.48 It was also noted that Project TransmiT and CMP213 had been conducted in a transparent manner and so both existing and new Users were able to consider the potential risks that this change (to the TNUoS charging methodology) might (or might not) be approved by the Authority. There was also a concern that generation projects which for reasons other than CMP213 were considering terminating or closing would be able to inappropriately use such a transitional arrangement, thus undermining User Commitment and potentially exposing end consumers to additional costs.

9.49 Of these two options discussed, the Full TEC reduction only option received more support within the Workgroup than the "range of TEC reductions" option, because this was seen as being less complex to administer/monitor, and less prone to potential gaming. However, neither option received majority Workgroup support and they were not progressed further.

Optional Grandfathering

9.50 Some responses to the Workgroup consultation and within the Workgroup argued that whichever of the four proposed implementation options were chosen, the notice period required by generator Users would still be insufficient. This is because generation Users may still be tied into contractual arrangements which require varying amounts of notice to be released from (e.g. power sales agreements, fuel and staffing contracts). Other members of the Workgroup took a counter view noted that if this were the case then presumably such generation Users would equally be unable to respond to other future market changes (due to these contractual arrangements), such as might arise from, say, the proposed EMR / Capacity Mechanism arrangements.

9.51 Some of the implementation subgroup also felt that a shock to the market may occur if Users who are able to respond to the signal withdraw too quickly, prior to adequate new generation and transmission reinforcements being built elsewhere on the system, requiring costly System Operator actions to manage. Therefore transition arrangements may be seen as an opportunity to safeguard system security and keep plant open in the short and medium term, which may benefit the system rather than force closure through changes, which some argued could not necessarily have been envisaged when investments were made. Other members of the Workgroup took a counter view noting that such investments had often been made many years, if not decades, before and that other substantial changes to the charging (and market) arrangements had occurred without long term grandfathering; such as the introduction of the Pool (in 1990) ICRP (in 1992), NETA (in 2001) and BETTA (in 2005).

9.52 An option put forward to mitigate these concerns was optional grandfathering. This would in effect allow existing generation sites to opt out of the new charging methodology arrangements introduced by CMP213 for a fixed period. Users that did not opt to grandfather (on the existing 'status quo' charging methodology) would fall under the new CMP213 based charging methodology tariff regime, along with all new Users. For the avoidance of doubt, this would only be a 'one way' option - once a generation site had taken the grandfathering option it could not opt 'back' to the new CMP213 based arrangements at a later date until the end of the duration period (see below) when it would, automatically, default onto the new CMP213 based TNUoS tariffs.

9.53 The Workgroup discussed what the appropriate duration period for such a grandfathering arrangement should be. Although some felt that whole plant lifetime should be considered, on balance, the majority of the Workgroup felt that if such a grandfathering arrangement was chosen a maximum of 4 charging years would be the most suitable duration period. If codified, this would be with an absolute 31st March 2018 end date, regardless of the implementation date determined by the Authority for CMP213.

9.54 The Workgroup also discussed likely costs of optional grandfathering. It was estimated that these may be in the region of £100m per annum of redistributed revenues, but that further work would be required to determine the impact should this option be taken forward. It was proposed that any under-recovery could be placed into the generation residual, although this was seen as undesirable for those unsupportive of the optional grandfathering approach, as it would mean sharing the under-recovery across all generation Users (and therefore reducing the signal for Users on the new CMP213 based TNUoS tariffs).

9.55 The complexity of implementing optional grandfathering from a National Grid perspective was discussed. This option was seen as complex and more costly to administer than immediate or delayed implementation of the CMP213 based TNUoS tariffs. This is because National Grid would be required to run two separate charging methodologies and systems and would need to reconcile between these two for each charging year within the duration period. Also the process for Users choosing between optional grandfathering and the new CMP213 approaches would itself be complex.

9.56 A potential mechanism for reducing the complexity of this option was suggested, whereby National Grid would choose which charging methodology ('status quo' or CMP213) to put each generation User on. However, the basis on which National Grid would make this decision was unclear, and it may leave them open to challenge, and therefore User choice was seen by the Workgroup to sit most appropriately with this transition option.

9.57 Some Workgroup members felt that optional grandfathering arrangements were potentially discriminatory as it involves treated new generation Users differently to existing Users of the transmission system. There was also concern that it would set a precedent to grandfathering arrangements for other changes to the charging methodology in the future.

Conclusion

9.58 The Proposer confirmed that the CMP213 Original would allow for an Authority decision on the implementation date and would have no transitional or grandfathering arrangements included.

9.59 The Workgroup took an initial vote on which options had the greatest support. No option received majority support; however, the option deemed to have the most merit was the codified delayed implementation option as described in paragraph 9.34, should a date prior to 1st April 2015 be decided upon by the Authority.

9.60 It was noted, that, as the Original would allow for Authority discretion that effectively this codified delayed implementation option was covered within the Original which rendered a hard codified alternative irrelevant. Therefore the best approach for the Workgroup would be to state the range of arguments for and against this option within the Workgroup Report, as above, instead of formalising implementation and transitional approaches as WACMs.

Panel View

9.61 At their meeting on 31 May 2013, Panel Members each expressed a view on implementation of CMP213. These views are shown in the table below:

Panel Member	Views
Paul Jones	**April 2015** at the earliest. CMP213 involves significant changes which generators would not have been able to predict when entering into any affected contractual arrangements such as selling power ahead of time. This will undermine a number of players' existing investments in GB. If it is implemented it should be under sensible implementation timescales in order to limit the damage that it will do to investor confidence. Although, generators will have been aware for some time that a change might occur and seen some indicative tariffs from the consultation, they would not have been able to predict which, if any, of the many options would be chosen. The date should be related to when the Authority decision is received - if the decision is received after the Autumn, it should be pushed back accordingly. Opposed to a mid-year change.
James Anderson	**April 2014.** 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". Therefore, implementation should be in as short a timescale as practicable to realise those benefits which supports option (2) April 2014. If this date is not achievable, then, despite the problems introduced by a mid-year tariff change, Option (3) mid-year 2014/15 would be the next best solution. Investors in GB's electricity industry are facing a great deal of uncertainty in the short to medium term. A number of workstreams are under way to address these changes, including CMP213, and it is important that decisions and implementation are made in a timely manner to ensure delivery of low carbon investment at an efficient cost. Indicative tariffs have been published reflective of the various methodologies considered by the Workgroup and the revised Transport & Tariff charging models have been made available to Users on request. As such, 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.

Michael Dodd	**April 2015** at the earliest as there could be the potential for windfall losses and gains. Opposed to a mid-year change.
Bob Brown	**April 2015** as the market needs time to adjust. Opposed to a mid-year change.
Simon Lord	**April 2015** but the decision needs to be indicated as soon as possible to give notice to parties.
Patrick Hynes	**April 2015.** The risk premium is already being built in. Opposed to a mid-year change.
Paul Mott	**April 2015,** there is not enough time for an April 2014 implementation.
Rob Hill	**April 2014.** It is clear from the consultation responses that moving to a dual background approach to the charging methodology will result in a material change to cash flow and operational procedures for a number of parties. However, these changes are not a surprise, having been developed over the last two years. Therefore once a decision is made it is appropriate that implementation should take place at the earliest year end charging point – April 2014 or 15. Mid-year changes should be avoided.
Garth Graham	**April 2014.** In addition to the comments already made by Panel Members above, with respect to April 2014, it is as soon as practicable for the reasons outlined in the Code Administrator Consultation. The next best option would be a mid-year change 2014/2015.

10 Views

Workgroup Conclusions

10.1 The Workgroup considered the aspects raised as potential alternative components in the three areas of the modification (sharing, HVDC and islands), which can be summarised below in Table 23:

Area of modification	Potential alternative area
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)

Table 23: Potential Alternative components

10.2 These potential alternative components were combined into 41 potential Workgroup Alternative CUSC Modification (WACM) proposals. These are shown in summary in Table 24 overleaf.

10.3 Prior to voting, Workgroup members stated their overall positions on these potential alternative components, having considered them against the Applicable CUSC Objectives prior to voting. The full summary of these views can be found in Annex 16.1.

10.4 The Workgroup then voted on which potential WACMs should be taken forward as formal Workgroup Alternative CUSC Modifications, believing that they better meet the Applicable CUSC Objectives than either the baseline (status quo) or CMP213 Original proposal. At this initial round of voting, twenty three potential WACMs did not receive majority support from the Workgroup. Results of this vote can be found in Annex 16.2.

10.5 Following the initial vote the Workgroup Chairman opted to retain eight WACMs on the basis that he believed that they better met the Applicable CUSC Objectives. The Chair explained the rationale for this. He argued that on the grounds of cost-reflectivity that all sharing options are potentially better than the baseline as the baseline includes no element of sharing. Removal of AC equivalent substation costs from HVDC expansion factors, whilst not in the baseline, had strong arguments on equitability, and thus competition. However, he was not convinced by the evidence presented for the hybrid ALF, in terms of cost reflectivity or complexity, and removal of VSC converter station costs. He noted the arguments in relation to removing the Quadrature Booster (QB) elements appeared to have a stronger rationale and therefore should at least be presented to the Authority. Considering the balance of evidence, the Chairman opted to retain eight potential alternatives - 4, 14, 16, 17, 18, 25, 31 and 32 - as WACMs.

10.6 Each Workgroup member then voted on (1) whether each alternative, including the Original proposal, better met the Applicable CUSC Objectives compared with the baseline; (2) whether each alternative better met the Applicable CUSC Objectives than the Original proposal, and (3) which proposal, including CUSC baseline, 'best' met the Applicable CUSC Objectives. Fifteen Workgroup members voted and the result of the vote is summarised in Table 25.

10.7 The majority of the Workgroup believed that the Original proposal better facilitated the Applicable CUSC Objectives than the CUSC baseline.

10.8 In terms of which proposal, including the CUSC baseline, best met the Applicable CUSC Objectives, a summary of options voted for is presented below in Table 26.

Options	**Number of Workgroup votes**
CUSC baseline	5
WACM 4	1
WACM 7	5
WACM 18	1
WACM 25	1
WACM 30	1
Abstention[26]	1

Table 26: Summary of options selected as "best" against CUSC objectives

[26] For the avoidance of doubt, there were no abstentions with respect to Vote (1) compared to the CUSC baseline or Vote (2) compared to the Original.

Main Components of CMP213	Original	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
Extent of Sharing																																										
No Diversity	x	x						x	x						x	x						x	x						x	x						x	x					
Diversity Method 1			x			x				x			x				x			x				x			x				x			x				x			x	
Diversity Method 2				x			x				x			x				x			x				x			x				x			x				x			x
Diversity Method 3					x							x							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	x				x		x	x			
YR - Hybrid		x				x	x		x				x	x		x				x	x		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	x	x	x	x	x	x																					
Specific EF; generic 50% Conv+100%Cable (AC sub)																													x	x	x	x	x	x	x	x	x	x	x	x	x	x
Specific EF; specific *x*% Conv. cost reduction (AC sub)																						x	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	x	x	x																						x	x	x	x	x	x	x
Specific EF; generic 50% Conv+100%Cable (AC sub)															x	x	x	x	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														

Table 24 – Combination of potential alternative elements combined into WACMs

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						
Vote: Better than baseline	8	7	9	6	3	8	5	7	7	7	7	7	4	2	6	7	7	8	5	2	8	7	8	6	3	8	7
Vote: Better than Original	N/A	2	6	5	6	4	6	7	4	5	6	4	1	2	5	9	8	7	5	4	7	8	7	3	3	7	6

Table 25 – Summary of voting on formal WACMs

CUSC Modification Panel Recommendation

10.9 At the meeting of the CUSC Modifications Panel on 31 May 2013, the Panel voted by majority that 8 of the options out of the Original and the 26 WACMs better facilitate the Applicable CUSC Objectives. The options that received majority Panel support against the Objectives were WACMs 2, 19, 21, 23, 26, 28, 30 and 33.

CUSC Modification Panel Discussion and Views

10.10 Prior to voting, the Panel had a discussion on an issue that had been highlighted with the draft legal text. This is in relation to an omission that had been identified in the diversity Alternatives under the definition of MITS Node, which under these Alternatives do not change from the baseline. The CMP213 Workgroup had agreed to divide the expansion factor of wider radial circuits by 1/SF (as discussed in paragraph 6.29 of this report) and CCF was also intended to apply to all radial circuits that have been designed to account for counter correlation (please see paragraph 4.109 of this report). However, in error, these changes were not included in the draft legal text provided in the Code Administrator Consultation and the subsequent Draft CUSC Modification Report that was circulated to the Industry. The Panel noted that the impact may be negligible as it is not envisaged that such transmission circuits will exist in the near to mid-future. The majority of the Panel felt that it would be pragmatic to raise a CUSC Modification at a later date if a diversity WACM is approved by the Authority in order to correct the omission. Therefore, the Panel carried out their vote with the legal text as it is currently drafted[27], on the basis that the error would be corrected if necessary in due course. Panel Members did however note that their vote would not change as a result of the legal text error, as the material impact was small.

10.11 The tables below show a breakdown of Panel Member's views on the key elements of CMP213 and their justification against the Applicable CUSC Objectives

Overall Panel Member Views:

Paul Jones (PJ)	
Network Capacity Sharing	A number of issues exist with this element of the proposal. The sharing methodology is based on scaling investment costs to individual stations based on factors which may affect constraint costs. This is predicated on the basis that the network is reinforced until the point that the marginal cost of network is equal to the marginal constraint cost. Although the SQSS has changed so that a proxy for a cost benefit analysis is used in the deterministic criteria, there is no evidence that this theoretical equilibrium is reached in practice, especially evenly across all constraint boundaries as is pointed out in the Bath University paper. Therefore, the concept that network investment costs can be scaled according to constraint cost influences has only been theoretically described and has not been adequately demonstrated as being actually applicable to real investment decisions. Notwithstanding this fundamental issue, the next stage of the proposed method, where circuits are allocated to two backgrounds, peak and year round, appears to have some limitations. Firstly, it is based on assessing under which background investment is most likely to be required, but assesses an intact system with no outages. In reality, the network will be planned to cope with outages and in a number of circumstances this will lead to different investment decisions than would be taken simply assuming an intact system. Therefore, is likely to lead to some

[27] Namely the draft legal text which was provided in the Code Administrator Consultation.

	circuits being allocated to incorrect backgrounds. Secondly, the proposal leads to entire circuits being allocated to either the peak or year round charges. Just because investment may be more important under one set of circumstances, it does not necessarily follow that it will not be necessary under the other conditions. The next problematic element is the scaling of constraint costs according to a generator's load factor. Although a generator's load factor will have some impact on constraint costs, this will not be constant throughout the year nor across boundaries, as appears to be the principle underpinning the original in particular. Also, other elements will determine the level of costs such as the spread between constraint actions and the amount of diversity behind a constraint. Whilst some the diversity options have sought to address the original's failure to deal with diversity, none of them adequately address the costs of constraints issue. The use of historic load factors is also an issue with some of the options. If a network is planned in proportion to the load factors that the network operators believe generators will be operating at, then a forward looking view of these is needed. Relying on a historic view as is proposed is overly simplistic and will miss the reality of what it happening on the system, especially at a time when load factors of plant are expected to change significantly, for example in reaction to a more decarbonised generation market. Additionally, if a charging signal is to be sent to generators based on their own load factor, then it is reasonable to expect generators to be able to respond to that signal. If they cannot do so by changing their load factor, then the aim of the signal is unclear. In other words, if we accept that a generator's load factor is indicative of how much it shares the network with other parties and therefore the level of charge it should pay, then why when this load factor is reduced does the charge not reduce accordingly? Hybrid ALF is a more appropriate approach. These concerns relate to the cost reflectivity of the proposal which means that these elements do not better meet Objective b). As a lack of cost reflectivity affects competition, neither do they meet a).
Inclusion of Parallel HVDC Circuits	This element of the proposals at least attempts to put in place arrangements for HVDC which the status quo currently does not have. The first element, to set the impedance of HVDC links to ensure consistent flows with the onshore system that it parallels is a sensible approach to ensure that the assets are neither under nor over represented in the transport model. This better facilitates Objectives a) and b). Proposals for generic reductions in converter costs have been based on one rough estimate of the split of converter station costs. It is not the basis on which to come up with generic reductions to be applied on an ongoing basis. It is also a very different approach to offshore charging in two important respects. Firstly, the whole cost of converters is charged to an offshore generator within the expansion factor. Secondly, specific costs are applied offshore on the basis (as stated by National Grid and Ofgem) that there is insufficient information to justify generic costs. Both of these mean that CMP213 generic reductions in converter costs represents a significant divergence in approach without an objective reason for doing so. That is, they are not relevantly different to warrant different treatment and therefore this seems unduly discriminatory. These options therefore do not better meet objective a), on the grounds that discriminatory treatment of market participants frustrates competition. Including 100% converter costs would be consistent with the offshore arrangements. Removing a proportion of costs on a specific basis would be more consistent that a generic approach, but will still be somewhat discriminatory compared with offshore. However, this could be limited if only those similar costs were socialised as are socialised in onshore ac substations.
Inclusion of Sub-Sea Island Connections	As with HVDC introducing arrangements is an improvement as there currently are none. However, as with the HVDC proposals removing generic proportions of converter stations is not justified given that it is based on one rough estimate of the split. Additionally, there are similar issues regarding discrimination between these arrangements and those for the converter stations for offshore generators. Including 100 percent converter costs would be consistent with the offshore charging

	arrangements. Removing a proportion of costs on a specific basis would be more consistent that a generic approach, but will still be somewhat discriminatory compared with offshore. However, this could be limited if only those similar costs were socialised as are socialised in onshore ac substations.
General Point	The updated Cost Benefit Analysis in National Grid's response to the Code Administrator's Consultation shows an increase cost to customers up to 2020 with no increased level of renewable build, nor lowering of carbon intensity of the generation market. Whilst there are limitations in such an exercise, if the CBA justification is negative and CMP213 is implemented anyway, this will undermine investor confidence as existing investments will have been undermined by a change with no apparent net benefit overall. The sharp increase in overall net benefit is noted in the CBA in the period from 2020 up to 2030. However, the change seems quite extreme and is less able to be relied on given that modelling out this far ahead is highly speculative in nature.

Simon Lord (SL)	
Network Capacity Sharing	The Workgroup 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. The group has developed a number of credible options that deal with this effect in a practical and balanced way. The original only using one of these key parameters ignores the benefits of low cost thermal bids to manage constraint costs. 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. On balance taking account of all the issues associated with diversity, Diversity 3 option which shares benefits across a group of generators is preferred to Diversity 1 or 2. Diversity 3 would still potential benefit for further change to remove a sharing benefit from base load low carbon generation that clearly would receive a disproportionate benefit. As a close second Diversity 2 which implements a similar methodology on a units basis would be acceptable. All options better meet Objective b).
Inclusion of Parallel HVDC Circuits	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 arbitrary 50% figure could be high or low and only a specific calculation for each converter station would achieve accurate results. Both the specific and the generic approach are supported and better meet the Applicable CUSC Objectives. 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.
Inclusion of Sub-Sea Island Connections	Islands connections have been incorporated in all of the proposals in a cost reflective way by treating either as on onshore or where a single circuit connection exists a reduced expansion factor applies. Therefore this better facilitates the Objectives.

Michael Dodd (MD)	
Network Capacity Sharing	It is important to state that incentives for the development of particularly types of generation should not be provided within network charging methodologies. These should, as far as is practicable recover costs from those that cause them thereby supporting a robustly competitive market for generation. If certain types of generation or location are to be particularly encouraged over others, this should be done through transparent subsidy mechanisms. None of the options provides a robustly more cost reflective methodology than the baseline. The original and alternatives based on a duel charging background to do not reflect the way investment is undertaken and incremental costs incurred. To base charges for low carbon generation on the supposition that they do not contribute to incremental cost at times of system peak has not been sufficiently demonstrated to be more cost-reflective than the status quo. The use of ALF as a proxy for constraint costs in the Original and Diversity Options 1 & 2 further compounds these issues. The analysis shows any correlation to break down in some areas of the country (southern importing zones, for example) and where there is a predominance of certain types of generation. There are other factors that have a much greater impact on constraint costs, in particular bid-offer prices and constraint boundary transfer capability. Further, it is not clear what signals are being provided to generators by the introduction of a further variable cost, in association with already inherent locational signal, and how they are to react to it. It is therefore not clear how this could improve competition in the generation market. Whilst the hybrid approach could reduce some of effects of averaging historic ALFs, the added complexity could have significant impacts for competition due to the inability of users (particularly thermal generators) to accurately forecast charges. Diversity Option 3 provides the benefit that the duel background approach is not used thereby better facilitating the ACOs a) & b) than the other alternatives but introducing a level of complexity and lack of "forecastability" that is detrimental to ACO a).
Inclusion of Parallel HVDC Circuits	There is clearly a need to update the current methodology to reflect the use of new HVDC technologies. Wherever possible this should be done consistently with the charging principles applied within the rest of the methodology and should have been the focus of a separate modification as this would have been less administratively burdensome and perhaps less contentious. That said, of the options presented, 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 would form the best approach.
Inclusion of Sub-Sea Island Connections	Similar to the above, the methodology needs to adopt to incorporate increased island capacity, linked by sub-sea connections. Wherever possible this should be done consistently with the charging principles applied within the rest of the methodology and should have been the focus of a separate modification as this would have been less administratively burdensome and perhaps less contentious. There has been little justification as to why island connections should be treated differently to other generators and as such the charging principles that form the basis of the wider methodology should apply here. As above, of the options presented, 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 would form the best approach.

James Anderson (JA)	
Network Capacity Sharing	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. The use of an Annualised Load Factor (ALF) is a suitable proxy for the parameters which determine the assessment of the costs imposed by different generators on the electricity transmission network through the proxy of their load factors.

	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 which have been quantified in the CMP213 Working Group Report as demonstrating an overall reduction in costs to consumers versus the current charging methodology. The benefit of adding considerable additional levels of complexity through the use of a sharing factor has not been fully justified and 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 of other generators (as at present) but would also vary according to the technology (carbon/low-carbon) and load factor of these 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. There has not been sufficient evidence presented to support the assumption that optimum network capacity sharing can only be achieved where there is a perfect match between Carbon and Low-Carbon generation nor to support capping the Sharing Factor under Diversity Methods 2 and 3 at 50%. Therefore, both these methods are significantly less cost reflective than the Original or Diversity Method 1. 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 (planed or unplanned), the trajectory of the carbon price support or other factors. Use of the Hybrid ALF would better reflect generators' usage of the transmission system by allowing sudden changes in load factor to be reflected in TNUoS charges without the significant delay inherent in a 5 year average and would therefore be more cost-reflective.
Inclusion of Parallel HVDC Circuits	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 of to be included in the Expansion Factors better facilitate Applicable Objective (b) than methods which derive from specific costs post construction. The evidence presented to the Workgroup indicates that a significant proportion of HVDC converter station costs (Approximately 50%) perform the same functions as AC substations whose costs are recovered through the Residual element of the TNUoS tariff and therefore the costs of these components should be excluded from the HVDC Expansion Factor. To the extent that elements of the HVDC converter station replicate the function of AC components such as 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. (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 businesses and reflects this in the Charging Methodology better facilitating ACO (C).
Inclusion of	(a) By clarifying the proposed charging methodology for Island generators, CMP213 better

Sub-Sea Island Connections	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).

Paul Mott (PM)	
Network Capacity Sharing	I consider the original in respect of network capacity sharing, to be worse than baseline. (I am merely commenting here, in this box, as requested, on the sharing aspect of the original). I consider that the original facilitates CUSC charging Objectives (a) and (b), worse than baseline, because the use of location-independent load factor, taking no account of diversity, as a crude dilutant of the year-round charge element, is too crude and inaccurate an approach. I consider sharing/diversity method 1 to be only slightly better than the original, and still worse than baseline as regards the issue addressed in this reply box. 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, 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, and one would not expect there to be any load factor dilution of the year round charge. 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. Methods 2 and 3 both, in terms of this box (how they treat sharing of network capacity), appear to be better than baseline. 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 I support method 3, as it removes this inherent issue with the use of ALF. The "hybrid" approach could be seen by some as a solution to the aforementioned issue, but seems to me to have hazards of its own, since plants choosing under that approach to challenge the load factor calculated for them within CMP213, will face a severe penalty if their load factor out-turns at a different level to the forecast they 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, I consider that, focussing only for the moment on the network capacity sharing aspect, 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.
Inclusion of Parallel HVDC Circuits	All variants of CMP213 are an improvement on baseline (charging objective c) against this box, but vary in the extent to which this is true of them. Baseline doesn't even have an impedance to assign to these circuits in the DC Load Flow model that lies at its core (though this could be addressed via a change to the charging statement). I have given careful consideration to the arguments around whether some of the HVDC converter costs, for HVDC offshore (“bootstrap”) links, should be removed from the relevant expansion factors, and hence from the locational charge elements. I 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. I realise that the AC substation equivalent costs are hard to identify, and that there may be cases where an AC substation wouldn't have been build had an AC link been used (onshore) instead of the "bootstrap". I have read all of the consultation responses (to both the January and May consultations), to see exactly what new evidence emerged in the consultation. I noted with interest the REA's evidence (in its May response) to the effect that 50% of the HVDC converter costs, may be a slight over-estimate for the AC substation equivalent costs. I note also the evidence from some parties who believe that it may be hard to ascertain component costs for each interconnector case by case, as the vendor may not give the information to National Grid. On balance I do accept that these costs should be removed from the converter cost in calculating the expansion factor for each HVDC "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 I would have preferred the specific approach that is favoured by respondents such as EON, Drax, and the REA. The generic proportion option would be based on one-off evidence, which may not be representative going forward. I do note NG’s comments in the second consultation document 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 I suggest the default generic information could be used as a substitute in this case. I do not consider that the case for the further removal from converter costs, of cost elements equivalent to the costs of ac quad boosters, has been 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.
Inclusion of Sub-Sea	All variants of CMP213 are a clear improvement on baseline (charging Objective c) against this box, but vary in the extent to which this is true of them. The improved MITS definition represents

Island Connections	an improvement in meeting charging objectives b and c; so does the new counter correlation factor. I have given careful consideration to the arguments around whether some of the converter costs, for new HVDC island links, should be removed from the relevant expansion factors, and hence from the locational charge elements. I 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. I realise that the AC substation equivalent costs are hard to identify, and that there may be cases where an AC substation wouldn't have been build had an AC link been able to be used instead of DC. I have read all of the consultation responses (to both the January and May consultations), to see exactly what new evidence emerged in the consultation. I noted with interest the REA's evidence (in its May response) to the effect that 50% of the HVDC converter costs, may be a slight over-estimate for the AC substation equivalent costs. I note also the evidence from some parties who believe that it may be hard to ascertain component costs for each island connection case by case, as the vendor may not give the information to National Grid. On balance I do accept that these costs should be removed from the converter cost in calculating the expansion factor for each island link. This will represent a slight over-compensation, since in some cases no AC substation would have been constructed had an AC connection been able to be used in place of DC, but it is simplest to adopt a rule that this cost element be removed. As to whether the substation-equivalent costs for each HVDC island link's converter should be calculated on a specific basis or from a generic basis: ideally I would have preferred the specific approach that is favoured by respondents such as EON, Drax, and the REA. The generic proportion option would be based on one-off evidence, which may not be representative going forward. I do note NG's comments in the second consultation document 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 I suggest the default generic information could be used as a substitute in this case. I do not consider that the case for the further removal from island B1converter costs, of cost elements equivalent to the costs of static compensation, has been made. I was intrigued by the reference in the REA's response to the final consultation to the possible exclusion of black start equivalent costs (one takes this to be intended to be read in the context of islands), but don't believe that's warranted.

Bob Brown (BB)	
Network Capacity Sharing	I have particularly studied the cost benefit analysis. This shows a potential increase in costs to customers up to 2020 with potential reductions thereafter. The longer term view builds uncertainties on uncertainties and there has to be doubt about the longer term view. I have reservations about the use of historic ALF in a market where generation mix is changing rapidly, and there appear to be a weaker locational signal and increased constraint costs as a consequence of the proposal. In conclusion, this does not better facilitate Applicable Objectives a) and b).
Inclusion of Parallel HVDC Circuits	The present arrangements need changing. I have doubts regarding the use of generic costs as each project will have unique challenges because of location and weather. There are potential discrimination aspects on the use of generic costs so it is therefore inappropriate and should be on a specific basis. Does not better facilitate the Objectives.
Inclusion of Sub-Sea Island Connections	Same view as above for HVDC.

Rob Hill (RH)	
Network Capacity Sharing	Given the increased level of intermittent generation on the transmission network the transport model and generation charging methodology needs enhancing to better reflect the incremental investment costs imposed by different types of generation. Introducing a dual background approach, reflecting the changes made to the network investment criteria under SQSS GSR009, which accurately reflects the benefit of sharing will increase cost reflectivity and support competition and ensure that the long term interests of consumers are better protected. Whilst the workgroup has debated many of the complexities of sharing, on balance annual load factor stands out as the more sensible proxy available with an option for generators to make this forward looking. It also seems appropriate to recognise diversity within a zone, without introducing excessive complexity or blunting the load factor signal.
Inclusion of Parallel HVDC Circuits	HVDC transmission technology should be included in the transport and tariff models carrying an equivalent cost base to HVAC in line with the existing methodology and include any operational network benefits. This is more cost reflective. Generic treatment supports simplicity and greater certainty and supports relevant objectives a and b.
Inclusion of Sub-Sea Island Connections	The transmission costs for island spurs should be modelled on an equivalent cost base to HVAC. Generic treatment supports simplicity and greater certainty.

Garth Graham (GG)	
Network Capacity Sharing	Agreed with the points already made by James Anderson. The Original better reflects the costs of the transmission system so it is better against ACO a) and also b) and c) as it takes into account transmission system developments and brings the transmission charging arrangements in line with the SQSS. Diversity 1 options better meet ACO a), b) and c) as there is a clear link between TNUoS Charging and the use of the Transmission system with the introduction of the peak and year-round elements and sharing in zones. The positive benefits in terms of the charging reflectivity and competition attributes outweigh the negatives effects. Diversity 2 option does not meet ACO a) or b) due, in particular, to the use of the arbitrary 50% figure. However, it better meets ACO c) but the benefits in terms of c) are outweighed by the dis-benefits under a) and b). Diversity 3 option is the same view as for Diversity 2. With regard to ALF, it is appropriate and better facilitates ACO a) and b) and is neutral on c). This is also the same for hybrid ALF.
Inclusion of Parallel HVDC Circuits	Charging 100% is not appropriate as there is clear evidence that a proportion of the convertor station is similar to onshore AC elements which are recovered via the residual. This evidence was obtained by a group of experts in HVDC technology who looked in detail at this issue and I can see no reason to doubt the veracity of that work. It is there appropriate to charge HVDC convertor station costs differently. While ‘specific’ is, intellectually, the most appropriate approach, from a practical perspective it may not be possible to obtain the required information so the ‘generic’ approach is the most pragmatic approach. Also persuaded by arguments for Quad Boosters (and STATCOM for islands).
Inclusion of Sub-Sea Island Connections	Same views as for HVDC above. A generic figure better meets the Objectives.

Patrick Hynes (PH)	
Network Capacity Sharing	Each of the main criteria are assessed against the baseline, and not broader options such as discussed under TAR or TransmiT. On this basis all of the proposed options, in the fact that they recognise sharing to, a greater or lesser degree, are better than the baseline on Objectives b) and c), with all better on Objective a) apart from Diversity 3 which is neutral. Assessment is made against the principles rather than the impact assessment as many of the assumptions within the impact assessment model are beyond the remit of the CUSC i.e. the impact of a future capacity mechanism. The modelling can only ever show a likely direction of travel rather than an absolute effect. I note that modelling by other parties show significantly different effects, presumably due to compound effect of different assumptions over a number of years. The Original better reflects the costs imposed by different types of generators on the electricity transmission system through use of dual background (SQSS links), and the introduction of annual load factor as a proxy for a specific generator's impact (its assumed availability and costs). Diversity 1 further increases this cost reflectivity through implicit management of sharing in peripheral parts of the system. Diversity 2 also achieves this, but have concerns over the justification of the 50% sharing limit. These concerns do not outweigh the wider benefits. There are broader concerns in regards to Diversity 3, not only with this 50% limit, but also that it does not reflect a specific generator's impact on transmission investment requirements, so neutral in terms of Objective a) (same as baseline), for Objective b) is a marginal improvement in terms of overall revenue apportionment but not for reflecting specific user impacts (which is the same as baseline so neutral), and an improvement in Objective c) as accounts for sharing of transmission that does occur. I note the increase in complexity caused by all Diversity alternatives, and recognise simplicity of Original and therefore benefits to competition (through supporting investment), although being slightly less cost reflective (which would be a marginal negative against competition). All factors considered we still believe they better meet Objectives b) and c), with Diversity 1 & 2 also better meeting Objective a).. Overall reflecting characteristics of specific generators will aid competition and cost reflectivity, and recognising the changes to the SQSS in the charging methodology will aid Objective c). In terms of Annual Load Factor derivation under the Hybrid options, recognise that reconciliation evaluation is an incentive rather than a cost reflective amount, that arguably a more accurate incentive may be more appropriate. However, along with submission of a forward looking ALF, we would expect a commercial regime. This very quickly then becomes a derivative of options discussed under TAR and moves towards the more theoretical solutions discussed and dismissed as part of TransmiT. On that basis, I believe the alternatives involving hybrid are still an improvement on the baseline, and could have the potential to be improved upon in the future.
Inclusion of Parallel HVDC Circuits	Believe that all options are an improvement on the baseline as they provide reasonable solutions for incorporating a technology which is not currently considered within the methodology (Objective c) improvement). Note the work done by Workgroup to socialise converter cost elements and believe it is pragmatic on a cost/benefit basis to apportion this socialisation on a generic basis. I recognise the benefits in favour of specific treatment, although note the general use of generic values in the expansion constant and factor calculations. Generic also has the advantage of being more transparent and predictable, and is arguably more cost reflective in terms of forward looking i.e. is not a cost recovery mechanism. Agree with the arguments for both 50% removal on the basis of AC equivalent, and also the additional 10% removal to recognise the controllability of flows on parallel bootstraps, and therefore the reduction in overall investment requirements. Overall, I believe all options put forward for HVDC have a level of cost reflectivity and therefore improve Objective b), whilst the transparent treatment of parallel HVDC in the methodology will aid Objective a), and recognising the use of and the benefits of HVDC improves on Objective c).

Inclusion of Sub-Sea Island Connections	Believe that all options are an improvement on the baseline as they provide reasonable solutions for incorporating a technology which is not currently considered within the methodology (Objective c) improvement) except those seeking to socialise 70% of converter costs. Note the work done by Workgroup to socialise converter cost elements and believe it is pragmatic on a cost/benefit basis to apportion this socialisation on a generic basis. However, have some sympathy for a specific treatment, and see this as a potential future proposal. Agree with the arguments for both 50% removal on the basis of AC equivalent. Not convinced by the arguments to remove an additional 20% of converter costs on the basis of STATCOM voltage support benefits, as do not believe there is necessarily a design requirement for this functionality in the majority of cases. On this basis do not believe that these alternatives represent an improvement in applicable CUSC Objective b) (cost reflectivity) over the baseline, whilst all other options for the treatment of Island connections are. Overall the transparent treatment of Islands in the methodology will aid objectives a) and c).

10.12 The result of the voting on whether each proposal better facilitates the Applicable CUSC Objectives is shown below. The justification for each proposal by each Panel Member is contained within Annex 18 in Volume 2 of this document. The table depicts the WACM numbers as agreed by the Workgroup.

Vote 1 – Whether each proposal better facilitate the Applicable CUSC Objectives overall. (Yes = Y, No =N, Abstain = A):

	PJ	JA	MD	BB	SL	PH	PM	RH	GG	Total For	Total Against
Original	N	N	N	N	N	Y	N	Y	Y	3	6
WACM1	N	N	N	N	N	Y	N	Y	Y	3	6
WACM2	N	A	N	N	Y	Y	Y	Y	Y	5	3
WACM3	N	N	N	N	Y	Y	Y	Y	N	4	5
WACM4	N	N	N	N	Y	Y	Y	Y	N	4	5
WACM5	N	N	N	N	Y	Y	N	Y	Y	4	5
WACM6	N	N	N	N	Y	Y	Y	Y	N	4	5
WACM7	N	Y	N	N	N	Y	N	Y	Y	4	5
WACM9	N	Y	N	N	N	Y	N	Y	Y	4	5
WACM12	N	Y	N	N	N	Y	N	Y	Y	4	5
WACM14	N	Y	N	N	N	Y	N	Y	Y	4	5
WACM16	N	Y	N	N	N	Y	N	Y	Y	4	5
WACM17	N	N	N	N	N	Y	Y	Y	N	3	6
WACM18	N	N	N	N	N	Y	Y	Y	N	3	6
WACM19	N	Y	N	N	N	Y	Y	Y	Y	5	4
WACM21	N	Y	N	N	N	Y	Y	Y	Y	5	4
WACM22	N	Y	N	N	N	Y	N	Y	Y	4	5
WACM23	N	Y	N	N	Y	Y	Y	Y	Y	6	3
WACM24	N	N	N	N	Y	Y	Y	Y	N	4	5
WACM25	N	N	N	N	Y	Y	Y	Y	N	4	5
WACM26	N	Y	N	N	Y	Y	Y	Y	Y	6	3
WACM28	N	Y	N	N	N	Y	Y	Y	Y	5	4
WACM30	N	Y	N	N	Y	Y	Y	Y	Y	6	3
WACM31	N	N	N	N	Y	Y	Y	Y	N	4	5

WACM32	**N**	**N**	**N**	**N**	**Y**	**Y**	**Y**	**Y**	**N**	**4**	**5**
WACM33	**N**	**Y**	**N**	**N**	**Y**	**Y**	**Y**	**Y**	**Y**	**6**	**3**
WACM40	**N**	**Y**	**N**	**N**	**N**	**Y**	**N**	**Y**	**Y**	**4**	**5**

10.13 Panel Members then provided their views on their individual 'best' option whereby 3 Panel Members considered that the baseline is 'best', 2 considered that WACM7 is 'best', 2 considered that WACM 25 is 'best', 1 considered that WACM16 is 'best' and 1 considered that WACM 19 is 'best. The vote to provide a 'best' option is custom and practice and does not form part of the CUSC Modifications Panel Recommendation Vote definition.

Vote 2: Which Option is best

Panel Member	**Option**
PJ	**Baseline**
JA	**WACM 7**
MD	**Baseline**
BB	**Baseline**
SL	**WACM 25**
PH	**WACM 16**
PM	**WACM 25**
RH	**WACM 19**
GG	**WACM 7**

11 The Case for Change

Assessment against Applicable CUSC Objectives

11.1 The Proposer considers that CMP213 would better facilitate the following Applicable CUSC objectives for the reasons set out in the CMP213 proposal shown in Annex 2.

11.2 For reference the Applicable CUSC Objectives 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.

12 Code Administrator Consultation Response Summary

12.1 26 responses were received to the Code Administrator Consultation. These responses are contained within Volume 3 of the draft Final Modification Report. The following table provides an overview of the representations received.

Company	Supportive	Comments
Repsol Nuevas Energias UK Limited	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014 – Ofgem should judge the commercial impacts on individual generators against the delayed implementation on the whole industry • ALF a suitable method. • Diversity methods involve subjective assumptions. • Prefer HVDC and islands options with removal of proportions of converter costs.
RenewableUK	Yes	• Preferred option: No preference (Original and alternatives all better facilitate CUSC objectives) • Preferred implementation: to ensure 2020 renewables target can be met.
Scottish Renewables	Yes	• Best option: WACM 7 • Preferred implementation: April 2014 – Ofgem should judge the commercial impacts on individual generators against the delayed implementation on the whole industry • ALF a suitable method. • Diversity methods involve subjective assumptions. • Prefer HVDC and islands options with removal of proportions of converter costs.
European Marine Energy Centre	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014 – Ofgem should judge the commercial impacts on individual generators against the delayed implementation on the whole industry • ALF a suitable method. • Diversity methods involve subjective assumptions. • Prefer HVDC and islands options with removal of proportions of converter costs
Renewable Energy Systems (RES)	Yes	• Preferred option: WACM 7 • Agrees with proposed implementation approach • ALF balances cost-reflectivity and stability • Diversity options seen to increase complexity, volatility and create barriers to entry. • Diversity 3 is not cost reflective and does not meet Terms of Reference. • For HVDC and Islands AC converter costs should be excluded in a generic basis.
Baillie Windfarm Limited (late submission)	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014 – Ofgem should judge the commercial impacts on individual generators against the delayed implementation on the whole industry

Company	Supportive	Comments
		• ALF a suitable method. • Diversity methods involve subjective assumptions. • Prefer HVDC and islands options with removal of proportions of converter costs
E.ON	No	• Do not believe Original or alternatives better facilitate CUSC objectives • Preferred implementation: Shouldn't implement at all but if so April 2015 better than April 2014 to avoid creating winners and losers. • Do not support ALF as a proxy (as not sole determinant, based on past circumstance and ignores demand). • Do not support Diversity methods (introduces undue complexity). • Prefer specific HVDC and island converter cost removal. • Would support an alternative with HVDC and islands elements only.
SSE	Yes	• Preferred option: WACM 7 • Preferred implementation: As soon as possible, better for end consumers. Transition options should be avoided as costly, discriminatory and inconsistent with previous changes. • Sharing Original, HVDC and island elements all better facilitate (a), (b) and (c), ALF elements better facilitate (a) and (b), • Diversity options less cost reflective and more complex. Disagree with classifications into carbon / low-carbon and feel understate sharing as fail to take into account of non-concurrent running. • Supportive as much socialisation of converter cost elements as possible (would have supported 100% as a WACM).
Fairwind Orkney Ltd.	Yes	• Preferred option: WACM 7 • Do not state a preferred implementation option. • Sharing Original and Diversity 1 are better than CUSC baseline against all three objectives. Diversity 2 and 3 are worse.
University of Bath – Department of Electronic and Electrical Engineering (late submission)	No	• Do not believe Original or alternatives better facilitate CUSC objectives • Preferred implementation: Should not be implemented. • All options worse against (a) and (b), and neutral against (c). • Number of shortcomings with ALF. • Proposals would increase congestion costs.
Centrica (late submission)	No	• Do not believe Original or alternatives better facilitate CUSC objectives • Preferred implementation: Shouldn't implement at all but if so April 2015 best. This would also give time to reconvene the Workgroup. • Concerns over impact assessment results. • ALF is worse against (a) and (b), sharing Original also worse against (c).

Company	Supportive	Comments
		• 100% costs should be included for HVDC and island converter stations as most cost reflective.
GdF-Suez Energy UK - Europe	Yes	• Preferred option: WACM 31 • Preferred implementation: Agrees with overall approach but concerns about implementation prior to April 2015 as would subject some Users to charges they are not able to avoid. • Support WACM elements including Diversity 1 and 2 (Diversity 2 preference), hybrid or historic ALF. • Support generic removal of 50% converter costs for HVDC and islands. Above 50% would need to be for specific only. • Concern over dual background approach. Would have liked a single background ALF alternative.
ESBI	No	• Do not believe Original or alternatives better facilitate CUSC objectives • Preferred implementation: April 2015 to allow sufficient notice for generation. Do not support mid-year changes. • Preference for specific HVDC and islands converter cost removal. • Would support an alternative with HVDC and islands elements only. • Sharing options not favoured ALF not a suitable proxy and intermittent should contribute to peak security element.
ScottishPower and Scottish Power Renewables	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014, although would support a mid-year change. • Sharing Original and Diversity 1 elements better meet (a) and (b) • All sharing elements better meet (c) • HVDC and islands elements better meet (a) (b) and (c) • Supportive of hybrid ALF. • Prefer HVDC and islands options with removal of proportions of converter costs.
Drax Power Limited	Yes	• Preferred option: WACM 25 • Preferred implementation: April 2015 to allow parties to account for tariff changes. • Diversity 3 could be an improvement on the baseline but further evidence required. • Prefer specific HVDC and islands converter station cost removal. • Not supportive of hybrid ALF.
RWE Npower (including subsidiaries)	No	• Do not believe Original or alternatives better facilitate CUSC objectives • Does not believe proposals should be implemented, but if so transitional approach should be adopted with at least 2 complete charging years notice and a gradual transition thereafter. • Further consideration needed on a number of issues. • Concerns over impact assessment results.

Company	Supportive	Comments
EDF Energy	Yes	• Preferred option: WACM 25 • Preferred implementation: April 2015, if draft tariffs available prior to September 2013. No need for transitional arrangements. • Sharing Original and Diversity 1 worse against (a) and (b), but sharing Original better against (c). • Diversity 3 a preference as removes load factor element • Hybrid ALF not supported • HVDC and islands elements better meet (b) and (c). Preference for specific converter cost removal for AC equivalent element only.
Orkney Islands Council	Yes	• Preferred option: WACM 7 • No preferred implementation option but would support a decision at the soonest possibility. • Supportive of socialisation of some converter station costs. • Support ALF, MITS redefinition and application of CCF.
Aquamarine Power	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014 – Ofgem should judge the commercial impacts on individual generators against the delayed implementation on the whole industry • ALF a suitable method. • Diversity methods involve subjective assumptions. • Prefer HVDC and islands options with removal of proportions of converter costs.
BVG Associates (2 x identical responses received)	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014 – Ofgem should judge the commercial impacts on individual generators against the delayed implementation on the whole industry • ALF a suitable method. • Diversity methods involve subjective assumptions. • Prefer HVDC and islands options with removal of proportions of converter costs.
Uisenis Power Limited	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014 • Sharing Original achieves compromise between cost reflectivity and simplicity. • Support removal of HVDC and islands converter cost elements
Pelamis Wave Power	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014 – Ofgem should judge the commercial impacts on individual generators against the delayed implementation on the whole industry • ALF a suitable method. • Diversity methods involve subjective assumptions. • Prefer HVDC and islands options with removal of proportions of converter costs.
Highlands and Islands	Yes	• Preferred option: WACM 7 • Preferred implementation: April 2014

Company	Supportive	Comments
Partnership		• ALF a suitable method and sharing Original aligns with CUSC objectives • Support 50% removal converter station costs • Would like to have anticipatory application of CCF.
Eggborough Power Limited	No	• Do not believe Original or alternatives better facilitate CUSC objectives • Preferred implementation: April 2015 – allows generators time to adapt to the change. • Proposal reduces cost reflectivity • Neither mod nor alternatives achieve a robust way to charge for transmission when the market is changing on a broader basis.
Renewable Energy Association	Yes	• Preferred option: WACM 30 – best balance between simplicity and cost reflectivity. • Preferred implementation: 1st April. Support 2014 providing provisions made for generators to reduce their TEC if they wished to with less notice than normal • Original and alternatives all better facilitate CUSC objectives • Diversity 1 recognises deterioration of sharing when 1 plant type predominates in simplest fashion, whereas Diversity 3 does not recognise dual background. • Support 50% for removal of costs, and that would include QB benefits.
National Grid	Yes	• Preferred option: WACM 16 • Preferred implementation: April 2014 achievable but April 2015 may be better for the end consumer due to industry uncertainty. • Diversity 1 may be more complex but is more cost-reflective • Not supportive of ALF incorporating User forecast. • Support 60% removal of HVDC costs, 50% for islands.