Stage 04: Code Administrator Consultation

Connection and Use of System Code (CUSC)

CMP224

'Cap on the total TNUoS target revenue to be recovered from Generation Users'

This proposal seeks to introduce a cap on the annual generation TNUoS revenue so that the annual average transmission charges payable by generators in GB always stay within the range specified by the European Commission Regulation 838/2010.

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

Published on: 7 March 2014
Responses by: 28 March 2014

The Workgroup concludes:
That CMP224 WACM1 should be implemented as it better facilitates the Applicable CUSC Objectives.

High Impact:

Medium Impact:
All parties which are liable for TNUoS charges

Low Impact:

Contents

Any Questions?

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About this document

The purpose of this document is to consult on CMP224 with CUSC Parties and other interested industry members. Representations received in response to this consultation document will be included in the Code Administrator's CUSC Modification Report that will be furnished to the Authority for their decision.

Document Control

Version	Date	Author	Change Reference
1.0	7 March 2014	Code Administrator	Version to Industry

1 Summary

1.1 CMP224 was proposed by National Grid Electricity Transmission plc and submitted to the CUSC Modifications Panel (the Panel) for their consideration on 27th September 2013. A copy of the Proposal is provided in Annex 1. The Panel determined that the proposal should be considered by a Workgroup and that they should report back to the Panel within four months following a period of 15 business days for the Workgroup Consultation.

1.2 The Workgroup first met on 24th October 2013 and the members accepted the Terms of Reference. A copy of the Terms of Reference is provided in Annex 2. The Workgroup have considered the development of the Proposal, the issues raised by it, and considered whether the Proposal and the options for potential alternatives would better facilitate the Applicable CUSC Objectives.

1.3 CMP224 aims to introduce a cap on the annual generation Transmission Network Use of System (TNUoS) revenue so that the annual average transmission charges payable by Generation Users in GB always stay within the range specified by European Regulation (e.g. that currently specified under European Commission Regulation ('EC Regulation') 838/2010 Part B, paragraph 3, of € zero to €2.5 /MWh). Each year TNUoS tariffs would be set to result in the overall revenue received from GB generation being the lesser of:

(i) 27% of the total revenue to be recovered from GB Users via TNUoS tariffs; or

(ii) such a value that results in generation tariffs not exceeding the upper limit specified under EC Regulation (currently €2.5 /MWh).

Where the amount to be collected from generation was less than 27% then the shortfall would be collected from demand.

1.4 A number of options for potential Workgroup alternatives have been discussed by the Workgroup. These have mainly centred around the interpretation of how compliance with the EC Regulation should be calculated. In particular, these discussions have centred around whether the cost of some, all, or none of the local assets should be considered as 'connection' in the context of paragraph 2 (of Part B) of the EC Regulation. This interpretation significantly affects the timescales when GB generation charges based on the current Charging Methodology, are expected to breach the upper limit of EC Regulation. It is not intended that this Proposal changes what assets are considered Connection assets in the CUSC charging arrangements.

1.5 The Workgroup also discussed whether the calculation of compliance and any adjustment to the generation revenue contribution should be fixed based on forecast values; be reconciled; or possibly be forecast with an error margin. Along with this the Workgroup considered the notice period for confirming any change to the 'G/D' split. For instance, should it be confirmed when tariffs are set (two months' notice), or should any change be confirmed year ahead (12 months notice).

1.6 The Workgroup Consultation closed on 23rd January 2014 and 9 responses and a Workgroup Consultation Alternative Request were received. The final Workgroup meeting was held on 30th January 2014. The Original was confirmed as being calculated with all TNUoS charges and having two months' notice (noting National Grid would provide forecasts ahead of this.

1.7 The Workgroup developed three alternatives: WACM1, which is CMP224 original with 12 months' notice period; WACM2, removal of TNUoS associated with 'generation only spurs'; and WACM3, 12 months' notice period and the removal of generation only spurs. CMP224 Original and all of the three Alternatives have an error marginal (also referred to as bandwidth). At present this would result in a 7% marginal for the 2 months' notice period

(CMP224 Original and WACM2) and 14% for 12 months' notice period (WACM1 and WACM3).

1.8 The Workgroup voted unanimously that against the baseline both the Original and WACM1 better facilitate the Applicable CUSC Objectives. WACMs 2 and 3 votes were split (4/4) against the baseline. Against the Original proposal only WACM1 received majority support (7/8). WACMs 2 and 3 only received minority support (3/8). The Workgroup Chair acted to 'save' WACMs2 and 3 as he believes the removal of the generation only spur element would better facilitate the Applicable CUSC Objectives.

1.9 Ofgem asked National Grid to perform an Impact Assessment based on the Original and the three WACMs. National Grid performed the assessment and presented it to the CUSC Panel on 28th February 2014. The Panel agreed to include it in the Code Administrator Consultation and this can be found in Section 7.

1.10 At the CUSC Modifications Panel meeting on 28th February 2014, the Panel agreed that the Workgroup had met the Terms of Reference and accepted the Workgroup Report. The Panel agreed for CMP224 to progress to Code Administrator Consultation for a period of 15 working days.

1.11 This Code Administrator Consultation has been prepared in accordance with the Terms of the CUSC. An electronic copy can be found on the National Grid Website, http://www2.nationalgrid.com/uk/Industry-information/Electricity-codes/, along with the CUSC Modification Proposal Form.

National Grid's Opinion

1.12 National Grid believes that CMP224 better facilitates the Applicable CUSC Objectives as it takes into account the developments in the European legislation affecting the transmission licensee's transmission businesses and ensures that GB stays compliant with the legally binding European Commission Regulation.

2 Background

2.1 European Commission Regulation 838/2010[1] Part B (paragraph 3) applies a range of € zero to €2.5 /MWh for the annual average transmission charges payable by generators in GB.

2.2 ACER (the Agency for the Cooperation of European Regulators[2]) is currently carrying out a review of the appropriateness of this range for the period beyond December 2014. It was expected to provide its opinion to the European Commission by 1st January 2014 (although this opinion has been delayed until later in 2014. The Commission may choose to make changes in line with ACER's opinion, make other changes it deems appropriate or maintain the current ranges. It is important that the value of annual average generation transmission charges in GB remains within the current prescribed range and within any future revised range (if modified by the European Commission after ACER's review, as set out in paragraphs 4 and 5 of Part B of the EC Regulation) that may come into force from 1st January 2015.

2.3 Given the time to progress changes through the CUSC under normal governance, National Grid considered that raising a CUSC Modification Proposal earlier would allow the industry to debate the issues of how this affected GB arrangements in a timely manner prior to any change by the European Commission. Waiting until mid 2014 would restrict the consideration of the issues and possibly affect the ability of CUSC Parties to take account of the ramifications in their commercial agreements.

2.4 As stated in Part B, paragraph 2 of the EC Regulation, '*Annual average transmission charges paid by producers is annual total transmission tariff charges paid by producers divided by the total measured energy injected annually by producers to the transmission system of a Member State*'. Therefore the value of the annual average transmission charges payable by generators in GB is dependent on a number of parameters which include:

- the total level of generation output;
- TO Allowed Revenues; and
- the €/£ exchange rate.

2.5 These elements are subject to variability when TNUoS tariffs are set:

- The total level of generation output is subject to variability in GB demand and interconnector flows;
- TNUoS tariffs for a given year are based upon forecasts of TO Allowed Revenue and charging bases (number of customers who pay charges) and therefore may result in the over or under recovery of revenue in any charging year; and
- Exchange rates change with varying economic conditions.

2.6 Considering the historic level of variability observed for these parameters, it is not expected that the level of generation transmission charges in GB will breach the €2.5 /MWh upper limit specified by the EC Regulation in the immediate future (up to and including charging year 2014/15). However, it cannot be assumed with absolute certainty that the level of these transmission charges will remain within the € zero to €2.5 /MWh range beyond charging year 2014/15 (especially given that the outcome of the ACER review is presently unknown). In addition, if the European Commission were to lower or raise the €2.5 /MWh

[1] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF

[2] http://acernet.acer.europa.eu/portal/page/portal/ACER_HOME

figure applicable to GB from 1st January 2015 then this may change the timescales in which a breach is expected to occur. It should be noted that the breach timescales discussed here are in line with interpretation of EC Regulation which includes all TNUoS charges payable by GB generators for Use of System.

2.7 Currently, National Grid recovers 27% of TO allowed revenue from generation Users and 73% from demand Users (through Suppliers). However, this split of TNUoS charges in GB does not currently take into account the need for the annual average generation charges to remain within the range set by EC Regulation.

3 Modification Proposal

3.1 The defect is that under forecast conditions, the charges arising from GB charging arrangements are expected to exceed the range in the current EC Regulation of € zero to €2.5 /MWh for the annual average generation transmission charges in GB within the next few years (charging year 2015/16 in a worst case scenario).

3.2 The Proposer's solution is to introduce a cap on the proportion of TO allowed revenue recovered through GB generation transmission charges, to ensure that the €2.5 /MWh upper limit specified in European Commission Regulation 838/2010 Part B (paragraph 3) or any subsequent EC Regulation that applies a revision to that limit is not exceeded. Such a cap would be applied in a way that would fix the proportion of TO allowed revenues recovered through GB generation transmission charges at the minimum of either (i) 27% of TO allowed revenues or (ii) such a lower amount as set to recover as close to 27% of TO allowed revenues as possible from GB generation Users whilst ensuring no breach of the aforementioned EC Regulation range.

3.3 The value for annual average transmission charges payable by generators in GB is calculated by dividing the total revenue collected from generation Users through Transmission Network Use of System (TNUoS) charges by the total measured energy injected into the Transmission Network. The total demand for any given year is an absolute number. However, the total generation TNUoS revenue can be adjusted to a level so that the annual average transmission charges payable by GB generators do not exceed the prescribed upper limit of the EC Regulation.

3.4 CUSC Section 14 Part 2 specifies that the total TNUoS revenue recovered will be split between generation and demand users at 27% and 73% respectively (the 'G/D split'). The G/D split ratio of 27% to 73% is a fixed ratio and it does not change, regardless of the overall revenue to be recovered from TNUoS charges in any given year. Taking into account the current trend of year-on-year increase in the overall TNUoS revenue in GB, along with generation TNUoS revenue being a fixed percentage (27%) and the EC Regulation limit being an absolute (currently €2.5/MWh), generation transmission charges will eventually exceed the EC Regulation upper limit (subject to the application of all generation TNUoS in the calculation).

3.5 The 27% is set on a best available forecast and does not lead to further changes should the forecast turn out to be wrong (e.g. if allowed revenue were over estimated). Due to the inherent risk of an error between the forecast and the actual outturn, the actual recovery is extremely unlikely to be exactly 27%. The Proposer intends to adopt the same approach of fixing tariffs on a forecast (and subsequently adopted a forecast including an error margin or 'bandwidth').

3.6 The Proposal suggests putting a cap on the annual generation TNUoS revenue so that the annual average transmission charges payable by generators in GB always stay within the range specified by the EC Regulation. The broader context of harmonisation of transmission tariffs across Europe to facilitate a single competitive market falls outside the remit of this Proposal. It was noted by a Workgroup member that 21 other Member States[3] are required, by the EC Regulation, to keep their transmission charges for generation to a range of range of zero to €0.5 /MWh.

3.7 The application of this cap will allow National Grid to reduce the overall TNUoS revenue collected from generation Users in GB. Therefore, the G/D split ratio may be modified when it is forecast that adherence to 27% for generation revenue does not fall within the range specified by the EC Regulation. Any modification to the G/D split ratio will affect the percentage of overall TNUoS revenue collected from both generation and demand Users in GB. However, the actual impact on individual Users' transmission tariffs is expected to be limited. It is currently expected that the G/D split ratio would only need minimal adjustment

[3] Those member states excluding Denmark, Sweden, Finland, Romania, Republic of Ireland plus Great Britain and Northern Ireland

to comply with the current range specified by the EC Regulation. However, if as part of the ongoing review process the European Commission were to reduce the upper limit of €2.5 /MWh for GB then this would lead to a greater adjustment in the G/D split. Conversely, if the European Commission were to increase the upper limit then this would lead to a lower (if any) adjustment in the G/D split. National Grid would also predict and publish the likelihood of the cap becoming ‘active’ in forecast tariffs (the Condition 5 and quarterly reports).

3.8 The cap will be linked to the range specified by the EC Regulation rather than the current limit in the regulation. As such the legal text states the ‘Upper limit of the range specified by European Commission Regulation 838/2010 Part B (paragraph 3) (or any subsequent regulation specifying such a limit) on Annual average transmission charge payable by generation. This mitigates the risk of any future revisions to this range requiring further CUSC changes directly as a result.

4 Summary of Workgroup Discussions

Presentation of Proposal

4.1 The Proposer outlined the defect that had been identified, namely the likelihood of a breach of the range set out in EC Regulation 838/2010 Part B, paragraph 3, over the next few years.

4.2 The EC Regulation 838/2010 Part B creates a common regulatory approach to transmission charging across the Member States. The EC Regulation states that the annual average transmission charges for generators in GB (plus Ireland and Northern Ireland) should remain within the range of € zero to €2.5 /MWh. These transmission charges shall exclude;

- Charges paid by producers [generators] for physical assets required for connection to the system or upgrade of the connection;
- Charges paid by producers [generators] related to ancillary services;
- Specific system losses paid by producers [generators].

4.3 Ancillary services have been considered analogous to charges under Balancing Services Use of System (BSUoS), and losses are managed through the Balancing and Settlement Code (BSC) as volume adjustments. Therefore these elements were not considered further by the Workgroup.

4.4 There is a risk that under current charging arrangements, the GB annual average transmission charge paid by generators may exceed the upper limit of €2.5 /MWh within the next couple of years, based on current forecasts. This assessment is built on the interpretation of the EC Regulation to include all charges payable by GB generators for Use of System, when calculating the annual average transmission charges payable by GB generators. The main driver for this Modification Proposal is to ensure this limit is not breached and therefore to ensure the GB charging arrangements remain compliant with European Legislation.

4.5 One Workgroup member noted that the objective of the EC Regulation included ensuring that *"Variations in charges faced by producers of electricity for access to the transmission system should not undermine the internal market. For this reason average charges for access to the network in Member States should be kept within a range which helps to ensure that the benefits of harmonisation are realised".* The member's view was that this suggested that the limits on annual average transmission charges paid by generators in all 28 Member States would harmonise gradually to a similar range, noting that 21 Member States currently operate in a range of € zero to €0.5 /MWh. It was further clarified within the Workgroup that although the EC Regulation takes a step closer towards harmonisation of tariffs to facilitate a single European energy market, it does not state they should converge on € zero /MWh. It was also noted that this Modification Proposal was not intended to address or support a broader move to tariff harmonisation across Europe, but it was about making sure that GB charges are compliant with the EC Regulation.

When will the limit be breached?

4.6 The Proposer presented analysis under two different scenarios (both based on the interpretation of the EC Regulation to include all charges payable by GB generators for Use of System when calculating the annual average transmission charges payable by GB generators) which both concluded similar timescales of a possible EC Regulation breach in the future. The initial analysis indicates that under both National Grid's "Slow Progression" and "Gone Green" scenarios, the point at which the €2.5 /MWh limit is exceeded is forecast to occur during charging year 2015/16. If, as permitted under the EC Regulation, the €2.5 /MWh upper limit for GB were to be reduced (or increased) from 1st January 2015 then a breach could occur sooner (or later) than the charging year 2015/16. This initial analysis used an assumed €/£ exchange rate based upon the average of the maximum and minimum rates observed during the year up to 14th October 2013.

4.7 The Workgroup considered that it could be beneficial to use a forecast of future €/£ exchange rates as the fluctuation in exchange rate could have a significant effect when the €2.5 /MWh limit might be exceeded.

4.8 Forecasts produced by the Office of Budget Responsibility (OBR) were taken as a reasonable forecast of future exchange rates. It was agreed by the Workgroup that this was from a credible and reliable source. National Grid revised the initial analysis on this basis for both of the scenarios. As with the initial analysis, the revised view indicates that a breach of the €2.5 /MWh limit is forecast from charging year 2015/16 onwards. This updated analysis is presented below in Figure 1 and Figure 2:

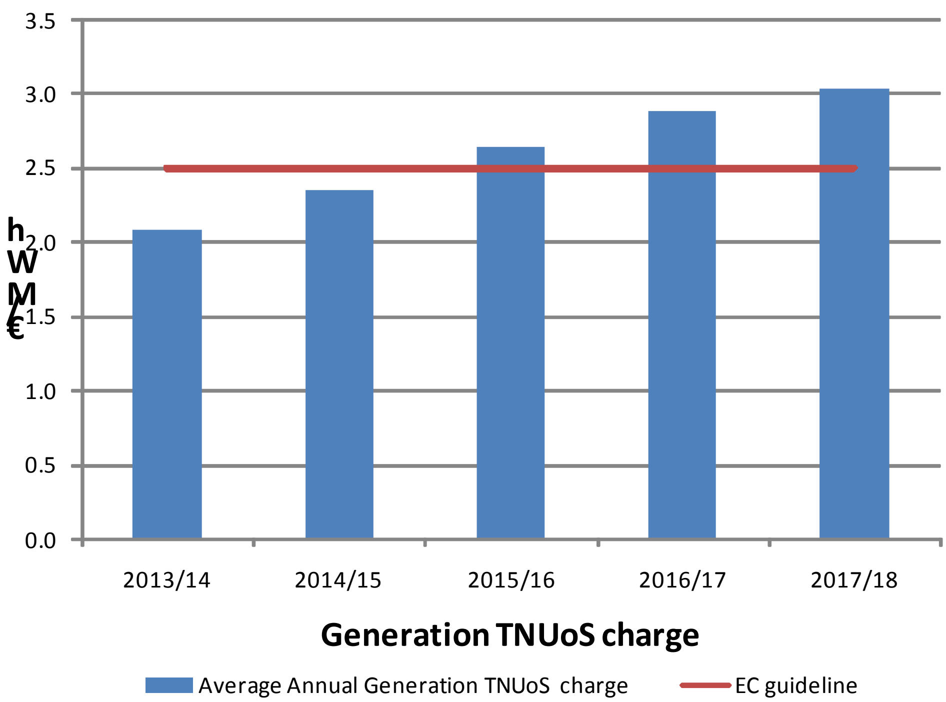


Figure 1 Forecast performance against EC Regulation 838/2010 under the National Grid Slow Progression scenario

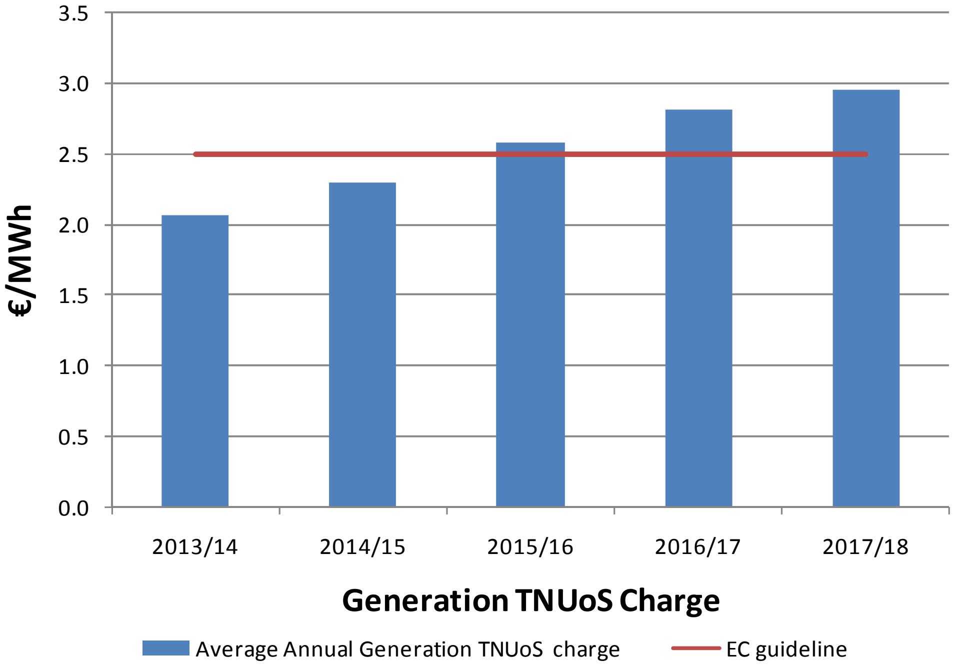


Figure 2 Forecast performance against EC Regulation 838/2010 under the National Grid Gone Green scenario

What uncertainties are there?

4.9 The Workgroup discussed that changes to several variables could lead to the € zero to €2.5 / MWh range being exceeded. The primary variables were summarised as:

- TO Maximum Allowed Revenue (MAR) assumed when TNUoS charges are set, and subsequent changes affecting generation revenue recovery;
- the total volume of energy injected onto the transmission system by generation (highly dependent upon the total transmission system demand);
- €/£ exchange rate fluctuation;
- the outcome of the ACER review of the limits prescribed by EC Regulation 838/2010 (described below);
- whether Local TNUoS charges should be included within the annual average transmission charges paid by generators in GB; and
- whether output from embedded generation should be included within the total volume of energy injected onto the transmission system by generation.

Changes to the EU range

4.10 The Workgroup discussed the ACER review of the EC Regulation ranges (not just for GB but all Member States). It was highlighted that ACER are currently reviewing the appropriateness of the ranges of annual average transmission charges paid by generators in the Member States for the period beyond 1st January 2015. National Grid has provided data to Ofgem for the ACER review in June 2013 and it is expected that ACER will provide its recommendations to the European Commission during 2014 (although this opinion has been delayed from January 2014.).

4.11 It was highlighted that there was a risk that the European Commission may decide to reduce the current GB €2.5 /MWh upper limit, which would have the effect of increasing the risk of GB breaching the EC Regulation sooner than expected. This was noted by the Workgroup as a possible risk to consider.

4.12 As timescales around the European Commission's decision regarding the ACER review were uncertain it was also thought that there was a possible risk of GB breaching the €2.5 /MWh upper limit within the charging year 2014/15, and it was agreed within the Workgroup that it was not appropriate to wait for the outcome of the ongoing review and that the Workgroup would need to work on the basis of the current range to progress the Modification Proposal. CUSC Modifications need to be assessed against the current baseline (including the current EC Regulation) and the Workgroup can only give a view against possible future changes. The Workgroup agreed that the ACER review could be an important factor in the consideration of the Proposal.

Consideration of the 'connection' in the context of the Regulation

4.13 In order to calculate whether the €2.5 /MWh upper limit has been exceeded, the Workgroup considered what costs TNUoS covers, and whether the calculation should be based on the whole of TNUoS or a subsection; e.g. removing 'Local charges'. The basis for this is that the EC Regulation 838/2010 (Part B, paragraph 2) states that:

'Annual average transmission charges paid by producers is annual total transmission tariff charges paid by producers divided by the total measured energy injected annually by producers to the transmission system of a Member State.

For the calculation set out at Point 3, transmission charges shall exclude:

(1) charges paid by producers for physical assets required for connection to the system or the upgrade of the connection;

(2) charges paid by producers related to ancillary services;

(3) specific system loss charges paid by producers.'

4.14 The Proposer presented the following diagram illustrating how Local TNUoS charges in GB are levied in respect of a number of assets on the transmission network:

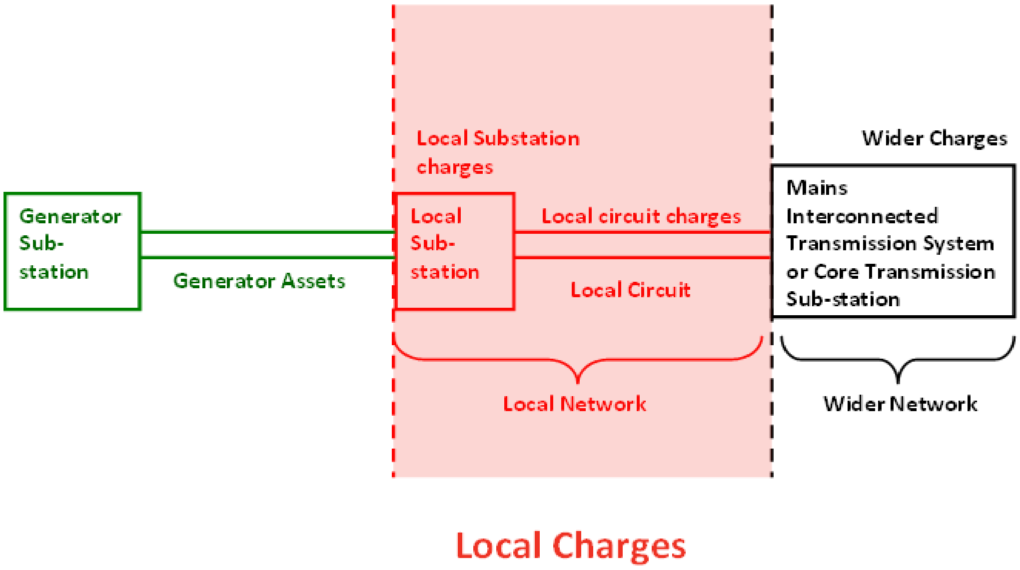


Figure 3 Generic representation of User local and wider assets for charging purposes

4.15 The Workgroup discussed whether or not assets which make up 'local charges' (those shown in red in Figure 3) could be considered as 'charges paid by generators for physical assets required for connection to the system' as referred to by EC Regulation 838/2010. If so, then they could possibly be excluded from the calculation of the annual average transmission charges for generators when assessing performance against the €2.5 /MWh upper limit prescribed in the EC Regulation. Along with this, the Workgroup considered what impact such an approach would have.

4.16 The Workgroup investigated what proportion of the GB generation TNUoS charges were made up of local charges. Figure 4 below was presented to the Workgroup as the current and future proportion of generation charges made up of local charges:

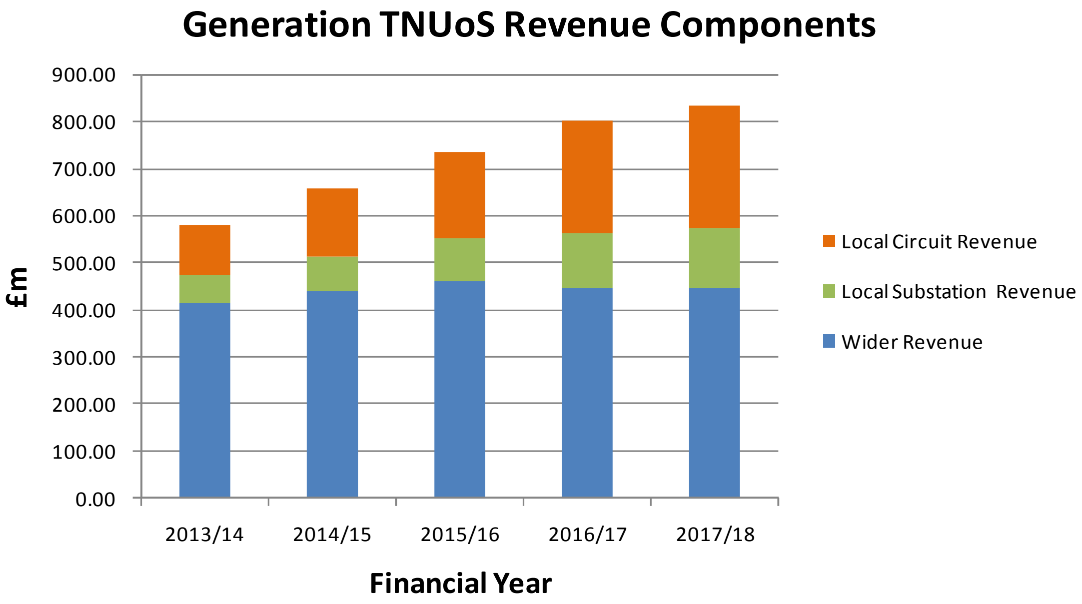


Figure 4 Generation TNUoS Revenue Components 2013/14 through to 2017/18

4.17 Figure 4 shows an increasing proportion of GB generation TNUoS revenue as local charges over the next five charging years. This increase in local charges increases the total generation TNUoS revenue. This also shows that the wider revenue shows little change over the five year period. This would mean that if the intention of the EC Regulation was to only include wider charges in the calculation of the annual average TNUoS charges paid by GB generation (i.e. excluding all local charges), a breach of the €2.5 /MWh upper limit would occur much later and probably not in the next five years.

4.18 Some members of the Workgroup felt that the wording of the exclusion within the EC Regulation was ambiguous in defining whether local charges or elements of the local charge may be excluded from the calculation of the annual average transmission charge. Some of the Workgroup believed that it was unclear as to what constituted "the transmission system" and 'physical assets required for connection' in the context of the EC Regulation, and that an attempt to clarify this should be made. Other Workgroup members disagreed noting that, in their view, what is meant by 'connection' and 'charges for connection' is very clearly set out in the CUSC (as per CUSC 2.14) so could be easily identified for the purposes of calculating if the €2.5 /MWh upper limit was breached (or not). In addition, they viewed the term 'transmission system' (with respect to 'connection') to also be clearly defined in both in the CUSC and in the EC Regulation itself. These Workgroup members therefore believed that all local charges should be included within the total of annual average transmission charges paid by generators in GB when considering the €2.5 /MWh upper limit.

4.19 The Workgroup considered a definition of the transmission system to be used for this Proposal. It was noted that within the EC Regulation transmission system is not a defined term. It was suggested that where such a definition did not exist in European Law, then the corresponding definition in Member State Law should be used, and if this did not exist, the definitions used in industry codes produced under such legislation should apply.

4.20 The consequence of this suggested approach was that the 'transmission system' in the EC Regulation should, with respect to GB, be interpreted as meaning (the CUSC definition of the NETS):

> the system consisting (wholly or mainly) of high voltage electric wires owned or operated by transmission licensees within **Great Britain** and **Offshore** and used for the transmission of electricity from one **Power Station** to a sub-station or to another **Power Station** or between sub-stations or to or from any **External Interconnection** and includes any **Plant** and **Apparatus** or meters owned or operated by any transmission

licensee within **Great Britain** and **Offshore** in connection with the transmission of electricity but shall not include **Remote Transmission Assets.**

4.21 Some Workgroup members considered that the EC Regulation had not been drafted with the GB definition necessarily in mind and therefore this was maybe not a correct interpretation. It was also noted that this definition included assets that are charged as connection assets, and as a result it would not, in the view of some Workgroup members, be appropriate to use such a definition as the EC Regulation would become contradictory; i.e. it would also need to default to the GB codes definition of connection assets which are a subsection of NETS.

4.22 It was suggested by some Workgroup members that the use of the GB definition of NETS was a logical approach if assets subject to connection charges were removed. This would mean that the local network illustrated as red in figure 3 above would be considered as part of the overall transmission system, and should therefore be included within the calculation of the annual average transmission charges for generators for GB. It was suggested that this would be consistent with the location of the point of connection to the transmission system used for the calculation of connection charges as well as interruption payments. Some Workgroup members did not agree that this was a logical approach or the analogy with interruption arrangements. It was pointed out that using this definition would already be inconsistent with that used for the calculation of interruption payments for generators with user choice connections. Indeed it was not clear to some Workgroup members that GB interruption payment were relevant to the discussion.

4.23 It was questioned whether the charges for connection assets should be included within the calculation of the total GB annual average transmission charges, given the previously highlighted definition of the NETS, which includes connection assets. The general opinion of the Workgroup was that the intention of the EC Regulation was to exclude assets associated with connection to the transmission system for which connection charges are levied. However, it was less obvious where assets classified, in GB terms, as local assets had similar characteristics to connection assets.

Legal opinion on interpretation of regulation

4.24 The Ofgem representative suggested that the Workgroup may wish to obtain a form of legal opinion on the interpretation of the EC Regulation. This would seek to establish a possible legal view on whether excluding charges associated with local assets when calculating the annual average transmission charge payable by generation Users in GB was a reasonable interpretation of the EC Regulation.

4.25 It was agreed by the Workgroup that National Grid would seek advice from their legal team on the process that should be adopted in obtaining such a legal opinion. It was viewed that such practices are undertaken in relation to other GB industry codes (such as commissioning legal opinion) as the Code Administrator does not have its own legal experts. In the case of the CUSC, National Grid in its role as Code Administrator has access to the National Grid legal team to provide such advice. In the past, external legal advice has also been obtained for a CUSC Workgroup, however the Workgroup did not consider it was appropriate in this case. It was clarified that if an individual member of the Workgroup wishes to obtain a separate legal opinion they are welcome to provide this to the Workgroup. It was also understood that if Ofgem required legal advice to determine on the Proposal that they would need to procure this separately from the Workgroup process.

4.26 National Grid sought an opinion from their legal team based on the interpretation of whether the charges for local assets should be included or excluded from the calculation of the GB annual average transmission charges. Two questions were asked in order to obtain this opinion:

1. Given the wording of EC Regulation 838/2010 and the manner in which local charges are calculated, could the exclusion of particular charges from the calculation of the Annual average Transmission charge be interpreted as including local TNUoS charges?

2. Could such an interpretation be subject to challenge in the future?

A summary of the legal opinion that was obtained was presented to the Workgroup and consisted of the following points[4]:

- It is not clear on the face of the EC Regulation where the distinction between connection and network charges should be drawn;
- There is no detail or guidance notes published alongside the EC Regulation, there are only a few words within the EC Regulation (physical assets required for the connection or upgrade of the connection);
- The different thresholds which charges on generation may not exceed may have already been set accounting for individual charging regimes;
- The clearest interpretation seems to be to include what in the GB regime is set as 'Local TNUoS' charges (within the calculation of the annual average transmission charges);
- Excluding local charges (from the calculation of the annual average transmission charges paid by generation) leaves scope for challenge to the (GB) charging regime; and
- Potential implications can arise from enforcement.

4.27 The Workgroup noted the summary legal opinion from National Grid. However, the Workgroup were not able to agree, based on the summary legal opinion and their consideration of the baseline CUSC, as to whether it would be sensible to; (1) exclude a subset of local assets from, or (2) leave all local assets in, the calculation of annual average charges. This stems from different views as to what 'connection' should be interpreted as, when complying with the EC Regulation. Views for and against are presented in Table 1 below.

4.28 It was suggested that it would be up to the European Commission to decide whether the Workgroup's interpretation of the EC Regulation, subsequently approved by the Authority, is correct and it was suggested that a table with arguments in favour of and against different interpretations of the EC Regulation regarding the treatment of local charges be created to help understanding of the views. This was subsequently incorporated within Table 1, which can be found later in this section of the report.

Exclusion of a subset of Local TNUoS charges

4.29 There was discussion within the Workgroup about how local charges are calculated and whether aspects of this charge could be excluded from the calculation of the annual average transmission charges for GB. In most cases, charges in relation to local assets are based upon generic costs. However, there are some cases (mainly offshore) where charges for local assets are based upon specific costs as there is insufficient information available to enable a generic calculation.

4.30 The Workgroup considered a range of options:

i) exclude all Local TNUoS charges;
ii) exclude Local TNUoS charges for assets that are considered sole use;

[4] Text in brackets was added by the Workgroup for clarity

iii) exclude Local TNUoS charges for which assets are specifically costed;
iv) exclude Local TNUoS charges for assets that are part of a spur connection for the sole purpose of connecting generation to the MITS;
v) exclude Local TNUoS charges for assets that were built as part of the works undertaken to connect an individual generator; and
vi) exclude local substation charges.

4.31 Table 1 below outlines the Workgroup's initial assessment of the potential advantages and disadvantages of these options:

Table 1 Options for interpreting 'connection' when apply Regulation to GB arrangements

Options	Reasons for	Reasons against
i) All local charges (as per the CUSC definition)	• Could be considered as assets that are 'paid for by producers for physical assets required for connection to the system'. • Delays the timescales for action assumed to be required to avoid exceeding the current limit of €2.5/MWh on annual average generation charges. Limited impact on demand charges as a result. • Limits the affect of timings of OFTO appointments on performance against limit, due to targeting of revenue through local charges. • Decreases risk of mid-year tariff changes to avoid breach of limit – provides more certainty of charges.	• Interpretation may be challenged as the GB transmission system could be considered to be the NETS and thus connection to it includes all local and wider charges paid by generators – therefore some risk of infringement. • Possible inconsistency with existing areas of the CUSC (e.g. connection charges), causing potential unintended consequences? • Delays the addressing of the breaching of the €2.5 /MWh upper limit which, potentially, could undermine the internal market.

Options	Reasons for	Reasons against
ii) Sole use asset Local charges (where only one generator uses the assets – not shared)	• Could be considered as assets that are 'paid for by producers for physical assets required for connection to the system'. • Delays the timescales for action assumed to be required to avoid exceeding the current limit of €2.5/MWh on annual average generation charges. Limited impact on demand charges as a result. • Limits the affect of timings of OFTO appointments on performance against limit, where there was only one generator on the spur. • Decreases risk of mid-year tariff changes to avoid breach of limit – provides more certainty of charges.	• Interpretation may be challenged as the GB transmission system could be considered to be the NETS and thus connection to it includes all local and wider charges paid by generators – therefore some risk of infringement • Some local charges are not asset specific. • Possible inconsistency with existing areas of the CUSC (e.g. connection charges), causing potential unintended consequences? • It is not clear what sole use assets are. Sole use is subjective e.g. an asset could currently be sole use but potentially shareable. • Complicated if some local charges are made for a combination of both sole use and shared assets. • Delays the addressing of the breaching of the €2.5 /MWh upper limit which, potentially, could undermine the internal market. • Appears arbitrary and possibly drives inappropriate company structure
iii) Specifically 'costed' asset Local charges (assets charges based on actual rather than generic prices)	• Could be considered as assets that are 'paid for by producers for physical assets required for connection to the system'. • Delays the timescales for action assumed to be required to avoid exceeding the current limit of €2.5/MWh on annual average generation charges. Limited impact on demand charges as a result. • Limits the affect of timings of OFTO appointments on performance against limit, due to targeting of revenue through local charges. • Decreases risk of mid-year tariff changes to avoid breach of limit – provides more certainty of charges. • Easily identified – determined by references to existing charges. • Easier to administer – not temporal. • It's objective.	• Interpretation may be challenged as the GB transmission system could be considered to be the NETS and thus connection to it includes all local and wider charges paid by generators – therefore some risk of infringement • It could change with the CUSC. • Possible inconsistency with existing areas of the CUSC (e.g connection charges), causing potential unintended consequences? • Charges made in respect to one off works could be considered as included (although not part of the regulated revenue) – can avoid via definition; • Delays the addressing of the breaching of the €2.5 /MWh upper limit which, potentially, could undermine the internal market. • Inappropriate material consequences should charges become generic. • Its subjective

Options	Reasons for	Reasons against
iv) Local charges for radial spur connections used only for connecting generation to the MITS	• Could be considered as assets that are 'paid for by producers for physical assets required for connection to the system'. • Delays the timescales for action assumed to be required to avoid exceeding the current limit of €2.5/MWh on annual average generation charges. Limited impact on demand charges as a result. • Limits the affect of timings of OFTO appointments on performance against limit, due to targeting of revenue through local charges. • Decreases risk of mid-year tariff changes to avoid breach of limit – provides more certainty of charges. • Easily identified – determined by references to existing charges. • It's objective. • Assets concerned are required for physical connection to wider system.	• Interpretation may be challenged as the GB transmission system could be considered to be the NETS and thus connection to it includes all local and wider charges paid by generators – therefore some risk of infringement • Possible inconsistency with existing areas of the CUSC (e.g. connection charges), causing potential unintended consequences? • Delays the addressing of the breaching of the €2.5 /MWh upper limit which, potentially, could undermine the internal market. • Its subjective
v) Local charges for assets built as part of works facilitating a generation connection	• Could be considered as assets that are 'paid for by producers for physical assets required for connection to the system'. • Delays the timescales for action assumed to be required to avoid exceeding the current limit of €2.5/MWh on annual average generation charges. No impact on demand charges as a result. • Limits the affect of timings of OFTO appointments on performance against limit, due to targeting of revenue through local charges. • Decreases risk of mid-year tariff changes to avoid breach of limit – provides more certainty of charges. • They are the assets clearly needed for connection.	• Interpretation may be challenged as the GB transmission system could be considered to be the NETS and thus connection to it includes all local and wider charges paid by generators – therefore some risk of infringement • Temporal issues –back and forward. • Difficult to calculate objectively. • Difficult to allocate strategically built capacity. • Inconsistency if not applied in Europe. • Possible inconsistency with existing areas of the CUSC (e.g. connection charges), causing potential unintended consequences? • Delays the addressing of the breaching of the €2.5 /MWh upper limit which, potentially, could undermine the internal market.

Options	Reasons for	Reasons against
vi) Local substation charges	• Could be considered as assets that are 'paid for by producers for physical assets required for connection to the system'. • Delays the timescales for action assumed to be required to avoid exceeding the current limit of €2.5/MWh on annual average generation charges. Limits impact on demand charges as a result. • Limits the affect of timings of OFTO appointments on performance against limit, due to targeting of revenue through local charges. • Decreases risk of mid-year tariff changes to avoid breach of limit – provides more certainty of charges. • Required to physically connect.	• Interpretation may be challenged as the GB transmission system could be considered to be the NETS and thus connection to it includes all local and wider charges paid by generators – therefore some risk of infringement • Generic charges - not necessarily based upon installed assets. • Difficult to justify why charges for substation assets should be excluded, but those for certain circuit assets should not. • Possible inconsistency with existing areas of the CUSC (e.g. connection charges), causing potential unintended consequences? • Delays the addressing of the breaching of the €2.5 /MWh upper limit which, potentially, could undermine the internal market.

4.32 Once the arguments in favour and against each of the above options set out in Table 1 had been considered, the Workgroup discussed the viability of each option as a possible Workgroup Alternative CUSC Modification (WACM). Overall, the Workgroup considered that option (iv) appeared, at this stage, to be the strongest possible alternative in this area. However, at this stage the opinion of the Workgroup was split as to whether this approach provided a better solution than that which included all TNUoS charges (for local and wider assets) within the calculation of the GB annual average transmission charges; i.e. the Original Proposal.

4.33 Further to this, the Workgroup went on to consider examples of radial spur connections used only for connecting generation to the MITS that would be excluded from the GB annual average transmission charges under option (iv). These examples are included in Annex 4. These charges made up a large proportion of the annual average generation revenue, as seen below in Figure 5.

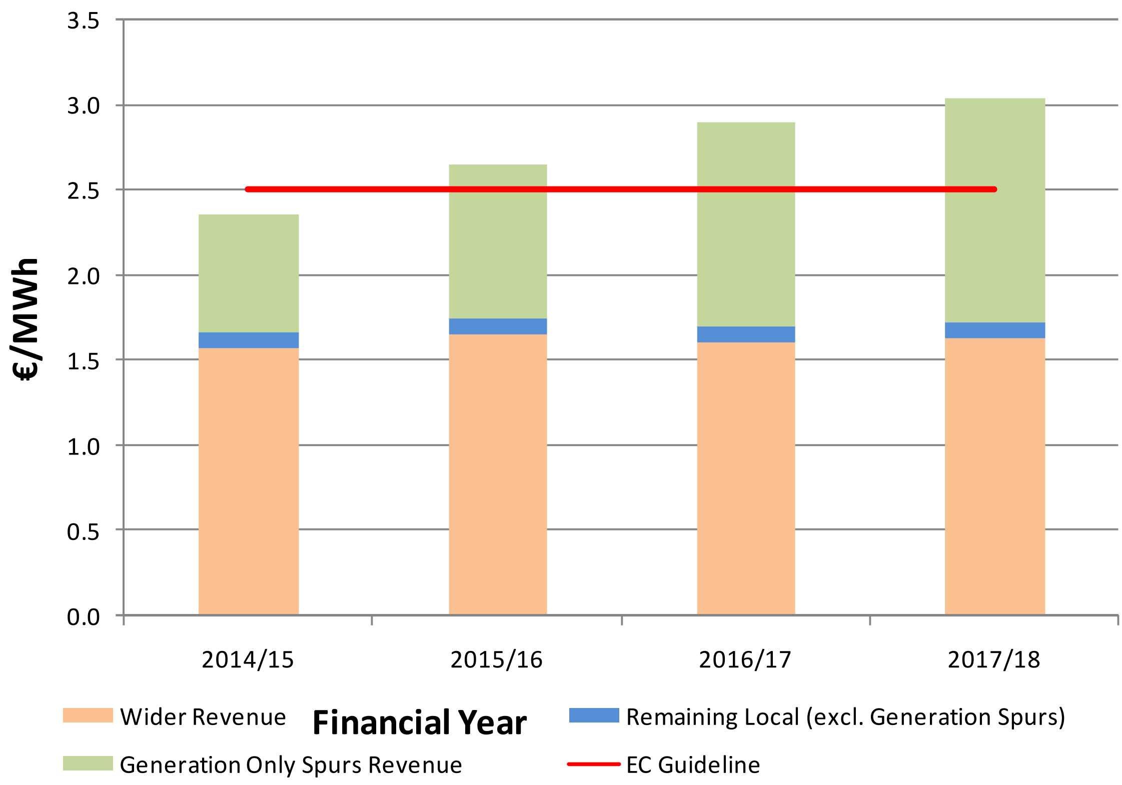


Figure 5: Annual average Generation TNUoS Revenue Components (Slow Progression)

4.34 It was noted that, based upon the current €2.5 /MWh upper limit, if the European Commission's interpretation of the EC Regulation was consistent with option (iv); i.e. excluded radial spur connections used only for connecting generation to the MITS from the calculation of the GB annual average transmission charges; it would be unlikely that a breach of the EC Regulation would occur in the near future.

4.35 Based upon the arguments for and against excluding charges listed under the remaining options, in Table 1 above, none of the Workgroup believed that any of these other solutions provided a preferable solution to that under option (iv), although some Workgroup members believed option (iv) was the least worst option.

4.36 There were some concerns within the Workgroup relating to future proofing the exclusion of charges for certain assets from the annual average transmission charges. For example, if it was proposed to exclude specific charges (such as those for offshore transmission assets) from the calculation then, in a few years time, when there is enough information to charge these generically, they would then be automatically included within the calculation for the GB annual average transmission charges, resulting in a step change in the annual average transmission charges. The majority of the Workgroup agreed that this is a risk that would have to be assessed at the time and suggested that the criteria used to calculate the proposed cap would need to be reconsidered at the time of such a change, to ensure that this remains appropriate.

Calculation and application of the proposed cap

4.37 The Workgroup moved on to discuss how the Proposal should be implemented once an appropriate method of determining the annual average transmission charges for GB had been established. The National Grid representative highlighted that there could potentially be a two stage process: one to identify a potential breach; and another to adjust the proportioning of revenue targeted to generation and demand. The Workgroup agreed that where such a solution was developed then the same benchmark forecast of the annual average transmission charges for GB should be used for both steps.

4.38 The Workgroup considered different options for calculating GB compliance with the €2.5 /MWh upper limit when it is set on a normal rolling year. These options were;

a. Best forecast based - National Grid would set the cap using their best forecasts of the three elements noted in paragraph 2.4, these are forecasts and are not entirely accurate so it may risk exceeding the €2.5 /MWh limit or the cap being more active than intended;

b. Based upon best forecast of the three elements noted in paragraph 2.4 with a reconciliation - National Grid would set the cap based on their best forecast, and if a breach subsequently became apparent transmission charges would be changed (potentially mid-year) to adjust the G/D split to ensure they did not breach the €2.5 /MWh limit; and

c. Based upon an adjusted forecast - National Grid would set the cap using their best forecasts of the three elements noted in paragraph 2.4 adjusted by an error margin 'bandwidth' to reduce the likelihood of a breach of the €2.5 /MWh limit occurring, should the best forecast not eventuate.

4.39 In order to assess the appropriateness of these options, the Workgroup questioned what would happen if the €2.5 /MWh limit was breached under any of these three scenarios. It was suggested that the level of action taken against GB for an infringement of the EC Regulation would potentially be based on the following questions:

i. could the breach have been identified prior to it occurring; and

ii. could any action have been taken to avoid such a breach?

4.40 In order to consider question (i) under options (a), (b) and (c), the Workgroup moved on to assess how each option would work in practice. In respect of question (ii) the Workgroup noted that it is possible, under the current GB charging arrangements, to effect a 'mid year' tariff change. As such the Workgroup agreed that whilst not necessarily desirable, it would be possible for action to be taken to avoid a GB breach of the €2.5 /MWh limit without the need to wait till the end of a particular charging year (if such a breach was either envisaged or actually occurred).

4.41 In relation to option (a), the National Grid representative presented an analysis for charging year 2015/16 to the Workgroup. This was based on a contracted generation background, assumed generation recovery and an average recovery in £/kW which is calculated by dividing the assumed generation recovery by contracted generation background. To meet the €2.5/MWh limit set by the EC Regulation the G/D split would need to be adjusting to 24.7 / 75.3. In the event that this was incorrect it was suggested that the mitigation could be that GB TNUoS tariffs had been set on the basis of Good Industry Practice.

4.42 It was also noted that whilst option (b) would ensure the correct recovery it would inject a level of uncertainty into the commercial arrangements. If a cap was introduced this would essentially provide a windfall gain to traders or generators that had traded based on a higher value. A counter view would be that if the change was not corrected as soon as it could be that this would essentially provide a windfall gain to traders or generators that had traded based on a lower value (which they had forecast themselves based on latest information).

4.43 This would also cause a windfall loss to suppliers who would be required to make up the difference, although in a competitive wholesale market there could be a lowering of the wholesale market price charged to suppliers which may match their windfall loss, dependent upon how far ahead energy was traded. This uncertainty could cause suppliers to introduce a risk premium based on the accuracy of National Grid forecasting of the three elements noted in paragraph 2.4. The Workgroup discussed and agreed that it would not be possible to determine the likely risk premium, although it was not expected to be significant. It was also questioned whether it would be fairer to have symmetrical arrangements where the reconciliation could increase the revenue collected from generation in the event that the annual average charges levied to generation fell below the upper limit specified in the EC Regulation. It was viewed that this could further increase the risk for parties to manage. It was recognised that a broader aim of the EC Regulation is to encourage cross border trading and from previous work on BSUoS it was recognised uncertainty on charges paid by GB generation in the short term had a negative impact on trading. Therefore the introduction of reconciliation could, overall, be considered counter productive.

4.44 The Workgroup then discussed how under option (c) a bandwidth (error margin) could be established. Several methods were discussed:

i. Using an ongoing mechanism, which sets a different bandwidth each time transmission tariffs are set;
ii. Using a fixed percentage bandwidth determined by the Workgroup and set out in the CUSC; or
iii. Using a fixed percentage bandwidth based on applying the mechanism derived under (i) at a given point in time (e.g. at a price control).

It was proposed that method (i) would adjust National Grid's best forecast of the three inputs into the annual average transmission charges in the following manner:

1. Use the TO Allowed Revenue increased by the maximum percentage over or under recovery error observed over a set number of [5] years;

2. Use the OBR forecast €/£ exchange rate inflated by the maximum percentage deviation from the annual average €/£ exchange rate observed over the same [5] year period; and

3. Use the forecasted output from generation reduced by the maximum demand forecast error observed in annual energy requirements forecasts by National Grid over the same [5] year period.

4.45 The Workgroup considered each of these points in turn, and the Workgroup agreed that the variability in the TO Allowed Revenue and annual energy requirements forecasts were intrinsically linked to that which would be observed in the GB total annual generation TNUoS charge and forecasted generation output, respectively. The Workgroup believed that there was a good understanding of this data and that the level of associated variability would be directly related to the quality of the forecasts National Grid uses when setting TNUoS tariffs. On this basis, it was viewed as reasonable to include such variability within the (error margin) bandwidth that would be applied under method (i).

4.46 In relation to variability in the €/£ exchange rate, the Workgroup viewed this as being driven by external factors and impractical for electricity industry participants to forecast with any degree of certainty. Following a discussion, it was agreed that National Grid was not best placed to judge the future variability in the €/£ exchange rate, and that this introduced a risk of an inappropriate error margin being assumed, potentially over inflating the required bandwidth and in itself creating uncertainty in the level of TNUoS charges. The Workgroup considered that providing a robust €/£ exchange rate forecast was used when assessing performance against the EC Regulation whilst setting TNUoS tariffs, then this provided a defendable position if a purely exchange rate driven breach of the EC Regulation occurred, and as a result no error margin would need to be considered. It was agreed by the Workgroup that as the €/£ exchange rate forecast published by the OBR was used by the

UK Government, that the rate published by the OBR each spring alongside the UK Government's Budget was suitable for the purpose of setting TNUoS tariffs for the following charging year (so as not to breach the €2.5 /MWh limit). In other words the OBR €/£ exchange rate forecast in spring 2014 would be used for the purposes of forecasting with respect to charging year 2015/16 (and so on for each subsequent charging year).

4.47 To provide a view of how the bandwidth would be calculated under method (i), the National Grid representative presented a comparison of historic forecasted annual transmission system energy consumption published in the Seven Year Statement (SYS), Electricity Ten Year Statement (ETYS) and Future Energy Scenarios (FES) publications and subsequently published outturn figures:

Year	Consumption forecast (y-1) TWh	Reported Outturn TWh	Forecast Error
2007/08	350.6	351.0	-0.1%
2008/09	348.2	337.6	3.1%
2009/10	325.9	325.4	0.1%
2010/11	323.7	314.7	2.9%
2011/12	314.4	312.5	0.6%
2012/13	312.7	Forecast basis changed	N/A

Table 2: Historic forecast transmission system energy consumption and associated outturns

4.48 Some Workgroup members questioned whether the energy consumption (generation output) takes embedded generation into account. It was clarified that small embedded and micro-generation are not included in the generation output as this generation is not visible on the Transmission Network. However, large embedded generation is included in the overall generation output.

4.49 It was noted that following customer feedback, National Grid had changed the way in which it reported energy consumption in the 2012 FES document to reflect total GB demand rather than purely demand observed on the transmission system, and that this presented an additional challenge when applying the mechanism on an ongoing basis (method (i) in particular).

4.50 To provide a view of how the bandwidth would be calculated under method (i), the National Grid representative presented a comparison of historic forecasted annual transmission system energy requirements (consumption) published in the Seven Year Statement (SYS), Electricity Ten Year Statement (ETYS) and Future Energy Scenarios (FES) publications and subsequently published outturn figures.

4.51 The National Grid representative also presented the outturn on historic charging years' under or over recovery of TO Allowed Revenues. This can be seen in **Table 3** below:

Table 3 Outturn of Historic years for G/D Split

Charging Year	Over (+ve) / Under(-ve) Recovery (%)
2012-13	0.1%
2011-12	-1.5%
2010-11	0.8%
2009-10	-3.1%
2008-09	1.0%

4.52 The Workgroup noted that this is indicative of the level of variability that could occur in transmission charges paid by GB generation in a given charging year, as both are driven by similar events, for example, the timing of the appointment of an Offshore TO and its associated revenue.

4.53 Taking into account the potential level of variability in the Allowed TO Revenues displayed in **Table 3** above, the Workgroup agreed that it would be good to have a bandwidth on the cap to avoid a breach of the €2.5/MWh limit. It was suggested that this could be a fixed value based upon the maximum error margin shown in Table 3 (3.1%).

4.54 The National Grid representative outlined a possible calculation method for such a (error margin) bandwidth using the proposed mechanism used to assess potential forecast errors. This would be done by using the following calculation of an inflated annual average transmission charges paid by generators (in GB) of:

$$= \frac{\textbf{Inflated Recovery x Inflated Exchange Rate Forecast}}{\textbf{Deflated Generation Output}}$$

4.55 The largest deviation from forecasts observed over a five year period was taken to calculate an inflated annual average transmission charges (based on the data in Table 2, Table 3 and paragraph 4.45), as follows:

$$= \frac{\textbf{(Forecast Recovery x 1.031) x (Forecast Exchange Rate x 1)}}{\textbf{Generation Output x 0.969}}$$

$$= \textbf{1.064 x } \frac{\textbf{Forecast Recovery x Forecast Exchange Rate}}{\textbf{Generation Output}}$$

4.56 Rounding up to the nearest 1%, applying this calculation would result in a (error margin) bandwidth of **7%.** This equates to setting GB generation TNUoS tariffs under a best forecast to a limit of €2.34 /MWh instead of the €2.5 MW/h upper limit set out in the EC Regulation (as presented in **Figure 6**). The Workgroup felt that applying this mechanism would be reasonable for the Proposal as there is a certain level of rationale behind the mechanism.

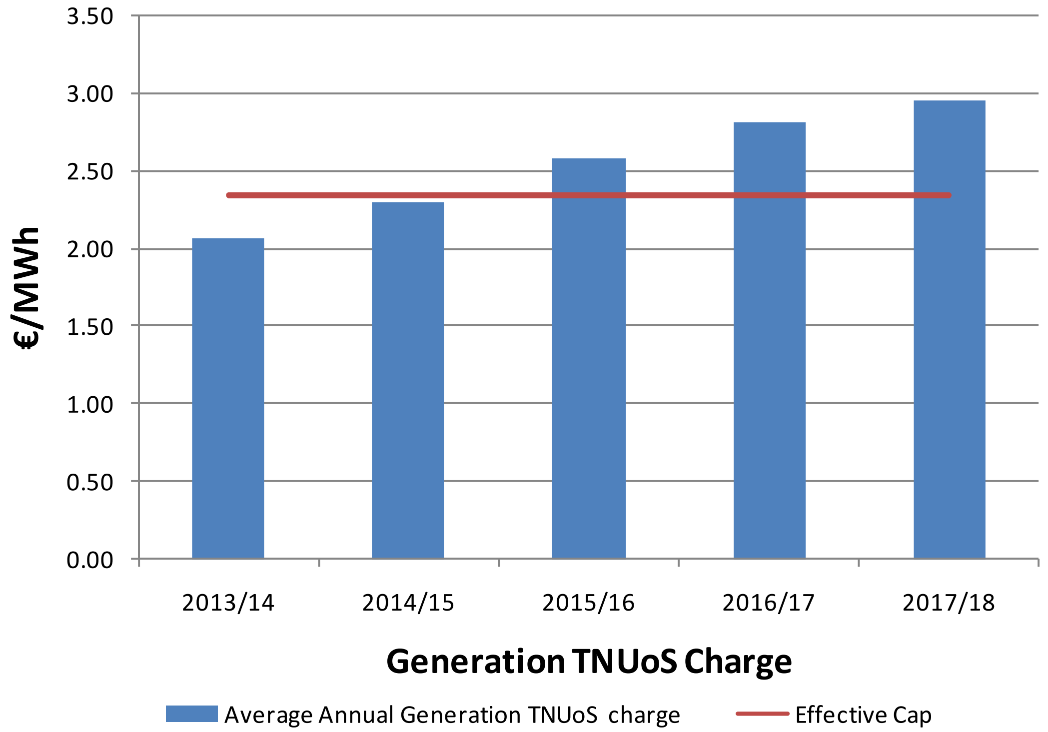


Figure 6: Annual average transmission charge paid by generation under the Gone Green scenario compared with a €2.34/MWh limit

4.57 The Workgroup agreed that it would be sensible to publish the current 7% bandwidth in the CUSC to aid transparency. However to ensure the CUSC remains future proof, the obligation would be in relation to apply the error forecasting methodology periodically; e.g. the absolute percentage would be kept under review by National Grid, who would consult stakeholders prior to any change(s).

4.58 The application of a 7% bandwidth in 2015/16 is forecast to result in the G/D split changing from 27% to 24% of TNUoS revenues being recovered through generation changes and 76% (instead of 73%) being recovered from demand charges. Assuming a generation background of 75GW and a peak demand of 55GW, this would have the effect of decreasing the generation residual by £1.06/kW and increasing the demand residual by £1.44/kW.

4.59 It was noted that if a bandwidth was calculated inclusive of the variation of the annual average €/£ exchange rate (4.3%) then this would see the 7% figure being revised upwards to 11%, which equated to applying limit of €2.25/MW/h (instead of the current €2.5/MWh limit). The application of a 11% bandwidth in 2015/16 is forecast to result in the G/D split changing from 27% to 23% of TNUoS revenues being recovered through generation changes and 77% (instead of 73%) being recovered from demand charges. Assuming a generation background of 75GW and a peak demand of 55GW, this would have the effect of decreasing the generation residual by £1.41/kW and increasing the demand residual by £1.92/kW.

4.60 The Workgroup also discussed how the bandwidth will be affected if it is fixed with a 12 months[5] notice instead of a two months notice coinciding with annual tariff changes. It was

[5] As subsequently addressed via WACM1 and WACM3 – see Section 5 for further details.

noted that accounting for 12 months notice would require data with a two year forecast period instead of one year forecast period as described in Table 2 and Table 3 in this section above. National Grid explained that sourcing credible data for this 12 months notice option which would allow the calculation of a reasonable bandwidth will be challenging.

4.61 The Workgroup discussed that a possible way to obtain the error margin associated with the bandwidth was to base it on the one year forecast data for energy consumption and TO Allowed Revenues and square the error i.e. 7% should be squared to account for a two year forecast (and 12 months notice period). This approach results in a bandwidth of 14%. The National Grid representative performed a similar calculation as used for the one year margin on the best available two year forecast data. This provided approximately the same result of 14%.

4.62 The application of a 14% bandwidth results in applying a limit of €2.15/MWh (instead of the current €2.5/MWh limit). For 2015/16 based on the Original (all TNUoS assets), this would result in 22% of the total TNUoS revenue being recovered from generation charges and 78% of the TNUoS revenue being recovered from demand charges. Assuming a generation background of 75GW and a peak demand of 55GW, this would have the effect of decreasing the generation residual by £1.76/kW and increasing the demand residual by £2.40/kW.

Workgroup Alternative CUSC Modifications

4.63 The Workgroup discussed possible Workgroup Alternative CUSC Modifications based upon its discussions to date. In addition to the potential alternative to remove local charges that related to spurs provided only for the purpose of connecting generation (option (iv) in Table 1), the Workgroup also discussed whether a 12 months notice be provided for the application of the cap and whether the G/D split should be restored to the current 27:73 in subsequent charging years following the application of the cap if this does not result in a breach of the limit set out in the EC Regulation. The Proposer highlighted that as the purpose of the Modification Proposal was only to avoid a breach of the EC Regulation the intention would be to revert back to a 27:73 split under this scenario.

4.64 In contrast, it was argued that the potential for the G/D split to return to 27:73 introduced a level of uncertainty that would provide difficulties to Suppliers in setting their retail prices. However, there was also a view that considered that Suppliers would benefit from the return to 27:73 in the short term as this would reduce their element of the total TNUoS charges for the charging year concerned (for which they may have already purchased their energy). It was agreed that the overall benefit depended upon whether or not Suppliers valued increased certainty greater than the potential increase in costs. However, it was noted that under this scenario there would be an increased risk placed on generators of a return to 27:73 and that this risk would be passed on, in the form of a risk premium, to Suppliers via the overall wholesale market price.

4.65 The Workgroup moved on to consider how an alternative in this area could work. It was suggested that the G/D split could be adjusted to ensure that the annual average charges included in the bandwidth in a future charging year (e.g. 2017/18) falls below the required limit. Under this solution, the same G/D split would apply to all charging years. It was highlighted that this solution could still encounter a breach, if there was a change in the Regulation €2.5 /MWh upper limit applied under the EC Regulation (e.g. following the ACER review). However, it was suggested that this could be adapted to be reassessed on an ongoing basis. The Workgroup agreed to consider this as a potential alternative CUSC modification.

5 Workgroup Alternatives

5.1 Section 4 of this report highlights the main areas of the Workgroup discussion regarding possible alternatives. Prior to agreeing the formal alternatives, the Proposer confirmed that the Original Proposal was based on the annual average transmission charges paid by generators GB including all TNUoS based charges (that is all local and wider charges); with the cap based on a forecast (with no reconciliation); using a bandwidth (currently calculated as 7%) to manage any forecast error set once; and set on a charging year basis (two months notice).

5.2 On this confirmation and noting the discussions covered in Section 4, the Workgroup considered that all the potential alternatives were made up from the following list:

a) Options around excluding some local charges from the annual average transmission charges figure for GB, these being:

i) All local charges (as per the CUSC definition); or

ii) Sole use asset Local charges (where only one generator uses the assets – not shared); or

iii) Specifically costed asset Local charges (assets charges based on actual rather than generic prices); or

iv) Charges for radial spur connections used only for connecting generation to the MITS; or

v) Local charges for assets built as part of works facilitating a generation connection; or

vi) Local substation charges;

b) Options with the cap based on:

i) Using actuals outturn and reconciliation; or

ii) A fixed bandwidth;

c) An error managed:

i) by a methodology; or

ii) A fixed bandwidth;

d) Compliance based on a calendar year (rather than a charging year); and

e) Whether the G/D Split should revert back to 27:73 following the application of the cap (if doing so would not result in a breach of the limit specified in the EC Regulation (currently €2.5 /MWh)).

5.3 The arguments for and against these various options are highlighted in the discussions set out in Section 4 of this report.

5.4 As part of the Workgroup Consultation, the Workgroup received a Workgroup Alternative CUSC Modification Request, this can be found in Annex 5 of the report. The party who made the request attended the final Workgroup meeting and was able to clarify a number of elements. The Workgroup Alternative CUSC Modification Request included;

a) Generation only spurs excluded from the calculation

b) Minimum of 12 months notice period; and

c) Ratchet mechanism (for changes to the G/D split, which would ensure that once the G/D split was changed, it would not revert back to the 27/73 ratio)

5.5 The Workgroup clarified that the 12 month notice period was in relation to changes to the G/D split and would not be for the implementation of the Modification itself (although a 12 month notice period would not apply in the initial year following potential implementation i.e. not for tariff setting for 2015/16 if approved pre January 2015), it was in order to future proof and to give a minimum notice period for changes to the G/D split.

5.6 The Workgroup went through each of the options (a)-(e) for potential alternatives highlighted in 5.2 above and concluded that there should be three WACMs for CMP224.

5.7 One Workgroup member put forward the ratchet mechanism as a potential WACM although this did not receive enough support from the Workgroup for it to become a formal WACM.

5.8 There was a majority support for more than the two months notice period that would be included within the Original Proposal. Six out of the eight Workgroup members supported this option which was formalised as a WACM. This WACM would contain all other aspects of the Original Proposal.

5.9 There was no majority support from the Workgroup for a WACM excluding charges for generation-only spurs with only three out of eight supporting this option. This was, however, taken forward as a WACM because the Chair believed this better facilitates the Applicable CUSC Objectives than the baseline and potentially the Original in some respects and, therefore exercised his right under the CUSC to 'save' the WACM option(s).

5.10 It was suggested that a WACM combining the two options above should also be put forward, this would exclude charges for generation-only spurs and include 12 month notice period. Only three out of eight Workgroup members supported this option. The Chair saved this option to put forward as a formal WACM for the same reasons above.

5.11 The Workgroup concluded that there would be three Workgroup Alternatives for CMP224, these are as follows;

WACM1: Original proposal but with a 12 month notice period;

WACM2: Original proposal but with generation only spurs excluded; and

WACM3: Original proposal but with generation only spurs excluded and a 12 month notice period.

5.12 The Workgroup then voted against the Original and the three WACMs, these votes can be seen in Section 8.

6 Proposed Implementation and Transition

6.1 The Workgroup's assumption was that, if implemented, the Proposal should come into practical effect prior to the start of the next charging year after the Authority decision, providing that the Authority decision is made by the 30th November preceding that charging year (i.e. a minimum of four months notice). Thus if an Authority decision is received prior to 30th November 2014, then the change would come into practical effect from 1st April 2015 with, in other words, the G/D split altered in accordance with the cap (if applicable) but with the draft TNUoS tariffs produced by National Grid in December 2014 and the final tariffs in January 2015. The Workgroup did not identify a need for any transition arrangements for CMP224.

6.2 The Workgroup discussed a number of potential implementation issues.

6.3 The Workgroup considered whether, given the National Grid legal opinion received in relation to the inclusion of Local TNUoS charges within the calculation of the GB annual average transmission charges for the purposes of compliance with the EC Regulation, National Grid would need to change the way in which this is reported to Ofgem and ACER. It was noted that National Grid has included Local Charges within their reporting to date, and so would not need change the way they report this on the basis of the legal opinion.

6.4 The Workgroup noted that there was a misalignment between the calendar year (January to December) on which the EC Regulation and the ACER review is based, and the charging year (April to March) that National Grid bases its charges (and reporting) on. It was agreed that the management of fulfilling the EC Regulation given this three month misalignment would need to be considered as part of the Original Proposal (and any WACM(s)).

6.5 There was an assumption that National Grid would continue to report on a charging year basis, although this may cause an implementation issue in the first year it was agreed that it would be a good idea to confirm that this will continue to be acceptable with the European Commission. However, such confirmation may not be forthcoming from them prior to an Authority decision on this Proposal.

6.6 The Workgroup discussed how this misalignment could possibly affect implementation timescales. It was stated that the practical application of the Proposal should occur at the start of the GB TNUoS charging year (1st April) with draft TNUoS charges produced by National Grid prior to the end of the preceding December and final TNUoS tariffs by the end of the preceding January. The Workgroup also stated that ultimately it would be up to the Authority to make the final decision as the Panel can only advise on an implementation date.

6.7 The Workgroup considered the risk that the ongoing ACER review (which was due to submit an opinion to the European Commission by 1st January 2014, but has since slipped to later in 2014) may result in the current €2.5 /MWh upper limit for GB set out within the EC Regulation being revised downwards, which would potentially be effective from 1st January 2015 (noting the possibility that the European Commission's final decision on ACER's opinion might be delayed). It was suggested that if the European Commission gave enough notice of this, National Grid could put forward a case to Ofgem to allow a mid-year TNUoS tariff change in order to ensure GB remains compliant with the (revised) € /MWh limit set out in the EC Regulation. All Workgroup members thought that this would not be a preferable option.

6.8 It was then suggested that National Grid would be able to adjust TNUoS tariffs as usual at the start of the charging year in order to comply with the (revised) EC Regulation limit. The Workgroup came up with two options to put forward to Ofgem of how to deal with a reduced € /MWh limit in the EC Regulation. These were:

i. As National Grid changes TNUoS tariffs and report on a charging year basis, they will base their compliance on the charging year rather than the calendar year. If the European Commission revises the € /MWh limit downward (from €2.5 /MWh) to take effect from 1st January 2015 there could potentially be a breach, by GB, for 3 months and then National Grid will change TNUoS tariffs from the start of the charging year 2015/16 (i.e. 1st April 2015) onwards in order to be compliant with the (revised) EC Regulation € /MWh limit; or

ii. If the European Commission revises the € /MWh limit downward (from €2.5 /MWh) to take effect from 1st January 2015, GB will breach the EC Regulation in the first 3 months (of 2015) but then compensate for this by reducing the TNUoS tariffs from 1st April 2015 onwards so that the TNUoS tariffs are compliant over the calendar year 2015 as the € /MWh limit in the EC Regulation is based on the annual average transmission charges.

6.9 The Workgroup felt that generally option (ii) would be a viable option, but this would depend upon the European Commission's opinion on whether this would be acceptable. Such an opinion may not be forthcoming from them prior to an Authority decision on this Proposal

6.10 These options will be provided to the Authority as part of the Final Modification Report to advise how National Grid would deal with the potential scenario of reduction in the € /MWh limit prescribed by the EC Regulation.

6.11 The Workgroup agreed that, if approved by the Authority, CMP224 should be implemented 10 days after the Authority's decision, i.e. the obligation comes into CUSC, but TNUoS charges would not immediately change until at least the following charging year. Views are invited on this implementation approach and timescales.

7 Impact and Assessment

Impact on the CUSC

7.1 CMP224 requires changes to Section 14, the TNUoS Charging Methodology.

7.2 The Legal text for the CMP224 Original and three WACMs was agreed by the Workgroup by e-mail after the Workgroup vote.

Impact on Greenhouse Gas Emissions

7.3 None identified.

Impact on Core Industry Documents

7.4 None identified.

Impact on other Industry Documents

7.5 None identified.

Impact Assessment

7.6 Ofgem asked National Grid to perform an Impact Assessment. National Grid performed the following assessment and presented it to the CUSC Panel on 28th February 2014. The Panel agreed to include it in the Code Administrator Consultation.

7.7 The following table shows the impact of an active cap on generation and demand revenues for the baseline and all the options including the Original Proposal and the three alternatives. The percentage of generation revenue has been calculated up to four decimal points for each option, e.g. for WACM2, year 2019/20 the '% Generation Revenue' figure is 27.0516%.

Options	Year	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Baseline - No Cap applied	% Generation Revenue	27%	27%	27%	27%	27%	27%	27%
	Generation revenue (£m)	669	715	777	791	827	913	944
	Demand revenue (£m)	1808	1934	2101	2139	2237	2469	2552
	Revenue collected from demand instead of generation (£m)	0	0	0	0	0	0	0
Original - Include generation spurs + 2 months notice	% Generation Revenue	26%	24%	22%	21%	20%	18%	17%
	Generation revenue (£m)	640	628	622	612	604	598	597
	Demand revenue (£m)	1838	2022	2256	2318	2460	2784	2899
	Revenue collected from demand instead of generation (£m)	29	87	155	179	223	315	347
WACM1 - Include generation spurs + 12 months notice	% Generation Revenue	24%	22%	20%	19%	18%	16%	16%
	Generation revenue (£m)	592	581	575	566	559	553	552
	Demand revenue (£m)	1886	2069	2302	2364	2506	2829	2944
	Revenue collected from demand instead of generation (£m)	77	134	202	225	269	360	392
WACM2 - Exclude generation spurs + 2 months notice	% Generation Revenue	35%	34%	32%	31%	30%	27%	26%
	Generation revenue (£m)	669	715	777	791	827	913	924
	Demand revenue (£m)	1808	1934	2101	2139	2237	2469	2572
	Revenue collected from demand instead of generation (£m)	0	0	0	0	0	0	20
WACM3 - Exclude generation spurs + 12 months notice	% Generation Revenue	34%	33%	30%	30%	28%	26%	25%
	Generation revenue (£m)	669	715	777	791	827	870	879
	Demand revenue (£m)	1808	1934	2101	2139	2237	2511	2616
	Revenue collected from demand instead of generation (£m)	0	0	0	0	0	43	64

7.8 The revenue from generation only spurs is included within the total generation TNUoS revenue for the Original and WACM1 whereas it is excluded for WACM2 and WACM3. For the Original and WACM2, the cap on generation revenue has been applied with an inbuilt error margin of 7%. For WACM1 and WACM3, the cap on generation revenue has been applied with an inbuilt error margin of 14%.

7.9 The proportion of revenue collected from generation for any charging year is the lower of 27% or '% Generation Revenue' figure for that year. Therefore, if the '% Generation Revenue' figure is higher than 27% then the revenue recovered from generation is 27% of the total TNUoS revenue and no shortfall is recovered from demand. However, where the '% Generation Revenue' figure is lower than 27% then the revenue recovered from generation is lower than 27% of the total TNUoS revenue and any shortfall is recovered from demand.

Q4: Please provide evidence of how the analysis discussed in Section 7 impacts end-consumer bills.

8 Views

Workgroup Conclusions

8.1 The Workgroup believes that the Terms of Reference have been fulfilled and CMP224 has been fully considered.

8.2 For reference the CUSC Objectives for the Use of System Charging Methodology are;

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

(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence 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; and

(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Workgroup vote

8.3 The Workgroup met on the 30th January 2014 and voted on the Original proposal and the 3 WACMs, the votes are set out below. The Workgroup voted by a majority of 5 to 3 that CMP224 WACM1 best facilitates the Applicable CUSC Objectives out of the options put forward and also better facilitates the Applicable CUSC Objectives than the baseline and so should be implemented.

8.4 The Workgroup noted that both Garth Graham and Paul Mott did not attend the final Workgroup meeting, although James Anderson was nominated, in accordance with the CUSC, by them to vote on their behalf.

Vote 1: Whether each proposal better facilitates the Applicable CUSC Objectives;

Original

WG Member	(a)	(b)	(c)	(d)	Overall
Tushar Singh		Yes	Yes	Yes	Yes
Garth Graham			Yes	Yes	Yes
James Anderson			Yes	Yes	Yes
Guy Phillips	No	No	Yes	Yes	Yes
Jeremy Gummow	No	No		Yes	Yes
Kyle Martin			Yes	Yes	Yes
Paul Mott			Yes	Yes	Yes
Cem Suleyman			Yes	Yes	Yes

Workgroup Comments

8.5 Tushar Singh – The Original strives to make a minimal adjustment to the G/D split ratio and not challenging existing cost-reflectivity considerations in the CUSC. Also, it takes into consideration developments in European Legislation and ensures that GB stays compliant with the legally binding EC Regulation.

8.6 Garth Graham – Better meets objective (c) as there is a risk that the growth in the TO's allowed revenues under RIIO-T1 leads to a real risk of breach of the Regulation. It better meets objective (d) as it would ensure compliance with the Regulation. The Original proposal is neutral against (a) and (b).

8.7 James Anderson – Better meets objective (c) as there is a risk that the growth in the TO's allowed revenues under RIIO-T1 leads to a real risk of breach of the Regulation. It better meets objective (d) as it would ensure compliance with the Regulation. The Original proposal is neutral against (a) and (b).

8.8 Guy Phillips – The Original better facilitates the ACOs although without addressing the issue of generation only spur connections, it could be detrimental to competition.

8.9 Jeremy Gummow – Inclusion of all TNUoS charges in the Regulation 838/2010 compliance is not necessarily a consistent approach to compliance with other EU states and doesn't recognise some of the UK's specific challenges. The option for compliance unnecessarily constrains the ability of NGET to levy TNUoS charges from generation, and to support an efficient transmission system for new generation. Further, this dilutes cost reflectivity and risks unprecedented gains and losses for existing generators. It also drives a higher proportion of charges to Suppliers, who are unable to influence this cost.

8.10 Kyle Martin – The Original proposal better facilitates CUSC objectives (c) and (d) as it ensures that there is a methodology that complies with the EC Regulation 838/2010 and ensures that GB is compliant with the Regulations by including all charges for physical connection. The Original proposal is neutral against (a) and (b).

8.11 Paul Mott – Better meets objectives (c) and (d) because it takes account of the developments in transmission licenses' transmission businesses and ensures GB compliance with EC Regulation 838/2010.

8.12 Cem Suleyman – better facilitates Applicable CUSC Objectives (ACOs) (c) and (d) by properly taking account of the developments in transmission licensees' transmission businesses and ensuring compliance with a legally binding decision of the European Commission. In particular, including all local TNUoS costs in the calculation and applying bandwidth to the forecast will reduce the risks of non-compliance. The effects on ACOs (a) and (b) will be non-existent (compared to the baseline), so the effect will be neutral.

WACM1

WG Member	(a)	(b)	(c)	(d)	Overall
Tushar Singh			Yes	Yes	Yes
Garth Graham			Yes	Yes	Yes
James Anderson			Yes	Yes	Yes
Guy Phillips	No	No	Yes	Yes	Yes
Jeremy Gummow	No	No		Yes	Yes
Kyle Martin			Yes	Yes	Yes
Paul Mott			Yes	Yes	Yes
Cem Suleyman			Yes	Yes	Yes

Workgroup comments

8.13 Tushar Singh – WACM 1 takes into account developments in European legislation and ensures that GB stays compliant with the legally binding EC Regulation.

8.14 Garth Graham – As per the Original proposal, however, the addition of a years notice of the G/D split to users improves the predictability of the tariffs, reducing uncertainty and thus helps facilitate economic decisions.

8.15 James Anderson – As per the Original proposal, however, the addition of a years notice of the G/D split to users improves the predictability of the tariffs, reducing uncertainty and thus helps facilitate economic decisions.

8.16 Guy Phillips – As the Original – but it does have the additional benefit of providing a period of notice to parties in anticipation of a change to the ratio of costs, which may dampen the short term impact to competition.

8.17 Jeremy Gummow – As per Original, however setting of the G/D split over a year ahead of charging decrease risks faced by Suppliers. This is therefore better than the Original.

8.18 Kyle Martin – same as the Original proposal, although the additional provision with 12 months notice period provides additional foresight to any changes in the G/D split which allows Users to factor any change into tariffs.

8.19 Paul Mott – Same benefits as the Original although the year's notice of the G/D split to users improves predictability of the tariffs reducing uncertainty.

8.20 Cem Suleyman – Same comments as Original although the use of 12 months notice may slightly increase the risks associated with non-compliance – although the application of additional bandwidth (compared to the Original) should offset this risk. WACM1 slightly better facilitates ACO (a) compared to the Original, as it provides market participants with some additional notice of a change to the G/D split. This results in a marginal improvement to the facilitation of effective competition in generation and supply relative to the Original. However, it should be noted that CMP224 itself is not the direct cause of a lack of notice provided to market participants. Rather the drafting of the EC Regulation itself does not allow Member States to phase in changes and thus provide (risk free) notice to market participants.

WACM2

WG Member	(a)	(b)	(c)	(d)	Overall
Tushar Singh			Yes	Yes	Yes
Garth Graham			No	No	No
James Anderson			No	No	No
Guy Phillips	Yes	Yes	Yes	Yes	Yes
Jeremy Gummow				Yes	Yes
Kyle Martin			No	No	No
Paul Mott			Yes	Yes	Yes
Cem Suleyman			No	No	No

Workgroup comments

8.21 Ofgem asked National Grid to perform an Impact Assessment. National Grid performed the following assessment and presented it to the CUSC Panel on 28th February. The Panel agreed to include it in the Code Administrator Consultation.

WACM3

WG Member	(a)	(b)	(c)	(d)	Overall
Tushar Singh			Yes	Yes	Yes
Garth Graham			No	No	No
James Anderson			No	No	No
Guy Phillips	Yes	Yes	Yes	Yes	Yes
Jeremy Gummow				Yes	Yes
Kyle Martin			No	No	No
Paul Mott			Yes	Yes	Yes
Cem Suleyman			No	No	No

Workgroup comments

8.22 Tushar Singh – Same comments as WACM 2

8.23 Garth Graham - As for WACM2

8.24 James Anderson – As for WACM2

8.25 Guy Phillips – As WACM2 but with the additional benefit of providing a period of notice to parties in anticipation of a change to the ration of costs recovered from Generation and demand.

8.26 Jeremy Gummow – As per WACM2, however, setting the G/D split over a year ahead of charging decreases the risks faced by supplier. This is therefore better than WACM2

8.27 Kyle Martin – same comments as outlined above in WACM2 vote.

8.28 Paul Mott – WACM2 only better facilitates the ACOs if, contrary to the Workgroup's legal advice, it turns out (when Ofgem seeks, one expects, its own legal advice) that charges for generation-only local spurs are to be excluded from the capped charges.

8.29 Cem Suleyman – same comments as WACM2 vote.

8.30 **Vote 2: Where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the Original Modification Proposal;**

WG Member	WACM1	WACM2	WACM3
Tushar Singh	No	No	No
Garth Graham	Yes	No	No
James Anderson	Yes	No	No
Guy Phillips	Yes	Yes	Yes
Jeremy Gummow	Yes	Yes	Yes
Kyle Martin	Yes	No	No
Paul Mott	Yes	Yes	Yes
Cem Suleyman	Yes	No	No

8.31 **Vote 3: Which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.**

WG Member	BEST Option
Tushar Singh	Original
Garth Graham	WACM1
James Anderson	WACM1
Guy Phillips	WACM3
Jeremy Gummow	WACM3
Kyle Martin	WACM1
Paul Mott	WACM1
Cem Suleyman	WACM1

National Grid initial view

8.32 National Grid considered that the CMP224 Original proposal would better facilitate Applicable CUSC Objectives (b) in that it would improve cost reflectivity, (c) in that it takes into account the developments in the transmission licensees' transmission businesses and (d) in that it would be compliant with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

9 Workgroup Consultation Responses

9.1 Nine responses and one Workgroup Consultation Alternative Request were received to the Workgroup Consultation. These responses and the Workgroup Consultation alternative request are contained within Annex 5 of this report. The following table provides an overview of the representations received;

Company	Initial views	Views against ACO's	Support implementation approach?	Other comments
Drax	• Original can be improved with additional notice – initially with less notice due to timescales • Supports application of a bandwidth. • Supports ratchet mechanism	• Yes – Original against ACO (c). Improvement to Original by introducing longer notice periods would also facilitate ACO (a).	• Yes	• No
EDF	• No ratchet m/c as it doesn't aid tariff stability. • Include all local charges • Additional Bandwidth	• Yes – Original against ACOs (b) and (c).	• Yes, provided Ofgem's decision is made by 30th Nov 14, enabling 4 months notice prior to charge changes. • No transitional requirements.	• No
E.On	• Both options (Original and potential WACM excluding local) should be presented to Ofgem. • No to excluding local charges • No to applying a bandwidth. • Doesn't support ratchet mechanism	• Both Original and potential WACM satisfy ECR and hence ACO (c).	• Yes	• No

Company	Initial views	Views against ACO's	Support implementation approach?	Other comments
Renewable Energy Association	• The proposal delays addressing the broader issue of harmonisation of transmission tariffs across EU market.	• No	• No	• No
RWEnpower	• Not enough notice given • Believe option (IV) should be considered as an option to ensure that charges remain stable. • 2 years notice desirable	• No	• No – Additional notice required along the lines of CMP201.	• The 2.50/MWh has been in place since 2010. Minor changes in G/D split could have been phased over time, short notice period not acceptable.
Scottish power	• Supports cap, local assets should be included	• None	• Yes with local included and sufficient bandwidth to support compliance	• No
Smartest Energy	• More radical review is required •	• No – random caps hinder competition and effect cost reflectivity.	• No – a cap is being calculated on forecast values, it may breach the regulation.	• It would be sensible to address G/D split on an enduring basis.
SSE	• It would look odd if GB change their criteria for the regulation	• The Original meeting the ACOs but don't think excluding	• Yes	• European study conclusions – higher GB charges are

Company	Initial views	Views against ACO's	Support implementation approach?	Other comments
	• Ofgem approve a calculation that puts NG in breach of the regulation.	local would meet the ACOs		already distorting the market and gerrymandering attempts should be replaced with lowering the GB range as per the rest of Europe.
VPI Immingham	• Agree with the intent of the proposal but a broader review is needed. • The proposal only addresses the issue arising from Regulation compliance and not the G/D Split itself.	• Yes – Original ACO (c)	• Yes	• No

9.2 The Workgroup discussed the Workgroup Consultation Responses and the Workgroup Alternative CUSC Modification Request in some detail, in order to agree on the best options for WACMs to be provided to the Authority alongside the Original Proposal.

10 How to Respond

10.1 If you wish to respond to this Code Administrator Consultation, please use the response proforma which can be found under CMP224 at the following link;

http://www2.nationalgrid.com/uk/Industry-information/Electricity-codes/Connection-and-Use-of-System-Code/

10.2 Responses are invited to the following questions;

1. **Do you believe that CMP224 better facilitates the Applicable CUSC Objectives? Please include your reasoning.**

2. **Do you support the proposed implementation approach as set out in Section 6? If not, please state why and provide an alternative suggestion where possible.**

3. **Do you have any comments on the draft Legal text?**

4. **Please provide evidence of how the analysis in Section 7 impacts end-consumer bills.**

5. **Do you have any other comments?**

10.3 Views are invited on the proposals outlined in this consultation, which should be received by 5pm on 28th March 2014. Please email your formal response to:

Cusc.team@nationalgrid.com

10.4 If you wish to submit a confidential response, please note the following:

Information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response marked "Private & Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the CUSC Modifications Panel or the industry and may therefore not influence the debate to the same extent as a non confidential response.

Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private & Confidential".

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP224

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal
Cap on the total TNUoS target revenue to be recovered from generation users
Submission Date
19/09/2013
Description of the Issue or Defect that the CUSC Modification Proposal seeks to address

European Commission Regulation 838/2010 applies a range of 0 - 2.5 €/MWh that average annual transmission charges payable by generators in GB must remain within. If in any given year the average annual generation transmission charges do not fall within this range, National Grid runs the risk of being non-compliant with the regulation. This range applies until the end of December 2014. ACER is currently carrying out a review of the appropriateness of this range for the period beyond December 2014 and will provide its opinion to the Commission by 1st January 2014. Therefore it is important that the average annual generation transmission charges remain within the current prescribed range until December 2014, and within the revised range (if modified after ACER's review) that may come into force from 1st January 2015.

The value of average annual transmission charges payable by generators is dependent on a number of parameters which include -

- Demand forecasts
- Revenue forecasts
- £/€ Exchange rate

Considering the impact of all these parameters along with the ACER review outcome, it is possible that the level of these charges does not breach the range specified by the EC regulation anytime soon. However, it cannot be assumed with absolute certainty that the level of these charges will remain within the range in future.

The driver for this proposal is to counter the risk of non-compliance with the EC regulation if indeed a breach of the range applied on generation transmission charges becomes a possibility in future. The broader context of harmonisation of transmission tariffs across Europe to facilitate a single competitive market falls outside the remit of this proposal. It is National Grid's view that the latter goal can only be accomplished by a comprehensive review of the Generation/Demand revenue split (G/D split in short). However, as the common regulatory approach to transmission charging across Europe is still evolving, it is recommended to carry out such an exercise when the European position in this area becomes clearer. This proposal does not aim to go into that level of detail.

Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes / No
No
Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information
BSC ☐ **Grid Code** ☐ **STC** ☐ **Other** ☐ *(please specify)*
Urgency Recommended: Yes / No
No
Justification for Urgency Recommendation
N/A
Self-Governance Recommended: Yes / No
No
Justification for Self-Governance Recommendation
N/A
Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?
We believe that this proposal does not have any interaction with an ongoing SCR.
Impact on Computer Systems and Processes used by CUSC Parties:
DCLF ICRP Transport Model

Details of any Related Modification to Other Industry Codes

None Identified

Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:

Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.

Use of System Charging Methodology

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

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

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

Full justification:

The European Commission Regulation 838/2010 is legally binding for all Transmission licensees across Europe. National Grid believes that this proposal ensures that it remains compliant with the European legislation and properly reflects National Grid's duties in the development of its transmission business, in the absence of an overarching direction of European charging arrangements.

Connection Charging Methodology

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

☐ (b) that compliance with the connection charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

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

☐ (d) in addition, the objective, in so far as consistent with sub-paragraphs (a) above, of facilitating competition in the carrying out of works for connection to the national electricity transmission system.

Full justification:

Additional details

Details of Proposer: (Organisation Name)	National Grid Electricity Transmission Ltd.
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or "National Consumer Council")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	Tushar Singh National Grid Electricity Transmission Ltd. 01926 656829 tushar.singh@nationalgrid.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	Adam Sims National Grid Electricity Transmission Ltd. 01926 655292 adam.sims@nationalgrid.com
Attachments (Yes/No): No	

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP224 WORKGROUP

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal CMP224 'Cap on the Total Target Revenue to be recovered from Generation Users' tabled by National Grid Electricity Transmission Plc at the Modifications Panel meeting on 27 September 2013.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

   (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.

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC Modification provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

Scope of work

4. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

   a) Consider the potential outcome of the ongoing ACER review on the ranges prescribed for annual average generation transmission charges, by the European regulation.
   b) Consider implementation timescales

c) Review illustrative legal text

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

9. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of 3 weeks as determined by the Modifications Panel.

11. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

    As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on 23 January 2014 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 31 January 2014.

Membership

13. It is recommended that the Workgroup has the following members:

Role	Name	Representing
Chairman	Patrick Hynes	National Grid
*National Grid Representative**	Tushar Singh (Proposer)	National Grid
*Industry Representatives**	Garth Graham	SSE
	James Anderson	Scottish Power
	Paul Mott	EDF
	Cem Suleyman	Drax Power
	Guy Philips	E.ON
	Jeremy Gummow	RWE
Authority Representatives	Donald Smith	Ofgem
Technical secretary	Jade Clarke	Code Administrator
Observers		

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

14. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP224 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

15. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise]. There may be up to three rounds of voting, as follows:

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;
- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal;
- Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

16. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible

opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

17. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

18. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

19. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

Appendix: Indicative Workgroup Timetable

The following timetable is indicative for the CMP224 Workgroup.

W/C 30 September	Send out request for WG nominations
24 October	Workgroup meeting 1
W/C 4 November	Workgroup meeting 2
13 November	Issue draft Workgroup Consultation for Workgroup comment (5 working days)
20 November	Deadline for comments on draft Workgroup Consultation
22 November	Publish Workgroup consultation (for 3 weeks)
13 December	Deadline for responses to Workgroup consultation
W/C 16 December	Post-consultation Workgroup meeting
9 January	Circulate draft Workgroup Report
16 January	Deadline for comment on Workgroup report
23 January	Submit final Workgroup report to Panel Secretary
31 January	Present Workgroup report to CUSC Modifications Panel

Annex 3 – Workgroup attendance register

Name	Organisation	Role	24/10/13	14/11/13	06/12/13	30/01/14
Patrick Hynes	National Grid	Chairman	Attended	Attended	Attended	Attended
Jade Clarke	National Grid	Technical Secretary	Attended	Attended	Attended	Attended
Tushar Singh	National Grid	Proposer / National Grid representative	Attended	Apologies	Attended	Attended
Wayne Mullins	National Grid	Proposer's Alternative / National Grid representative	Apologies	Attended	Attended	Apologies
Donald Smith	Ofgem	Authority representative	Teleconference	Attended	Teleconference	Attended
Garth Graham	SSE	Workgroup Member	Attended	Attended	Attended	Apologies
James Anderson	Scottish Power	Workgroup Member	Attended	Apologies	Attended	Attended
Cem Suleyman	DRAX	Workgroup Member	Attended	Apologies	Attended	Attended
Paul Mott	EDF Energy	Workgroup Member	Attended	Apologies	Teleconference	Apologies
Jeremy Gummow	RWE	Workgroup Member	Attended	Attended	Attended	Attended
Kyle Martin	Energy UK	Workgroup Member	Teleconference	Attended	Apologies	Teleconference
Guy Phillips	EON	Workgroup Member	Attended	Attended	Attended	Attended

Annex 4 – Radial spurs used only for connecting generation to the MITS

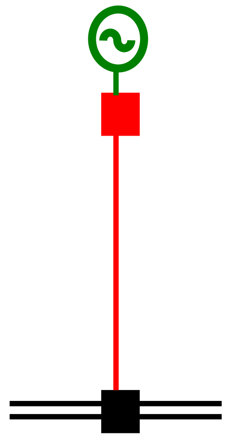
The following diagrams provide examples of radial spurs used only for connecting generation to the MITS. These assets are a subset of those for which local TNUoS charges are applied which:

(i) are solely used for connecting generation to the MITS (Main Integrated Transmission System); and

(ii) do not parallel the MITS.

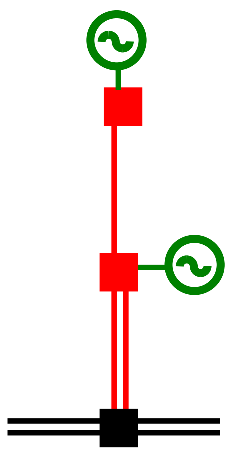
In these examples, the assets represented in red form the radial spurs used only for connecting generation to the MITS. Those in blue are assets not forming part of the spur, but form part of the assets for which a Local circuit charge[6] will be levied. Black circuits represent those assets which form part of the MITS, and green assets represent connection assets or assets owned by a generator.

Example 1



This example shows the simplest example of a single radial spur used only for connecting generation to the MITS, in the form of a single circuit. The circuit does not parallel the MITS, as it connects to a single MITS substation.

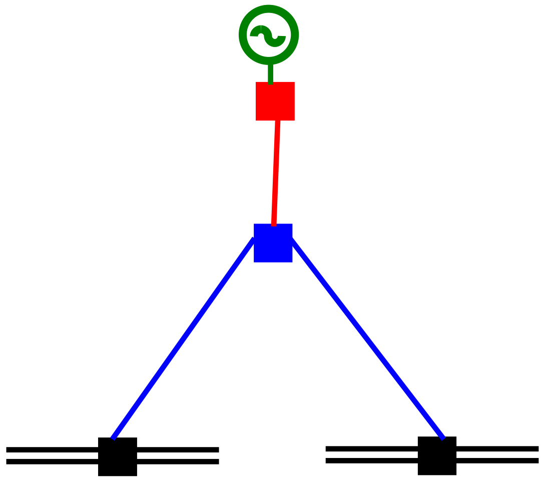
Example 2



[6] Local substation charges only apply for the first transmission substation to which a generator connects.

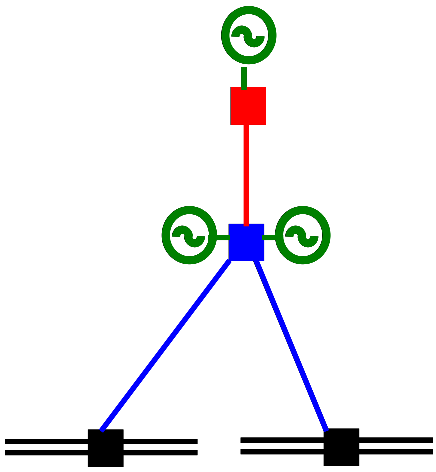
Building on example 1, this example shows a slightly more complex radial connection to the MITS comprising of two generation substations connected via a single circuit, with a double circuit connecting one of these to the MITS. All these assets form a single radial spur used only for connecting generation to the MITS.

Example 3



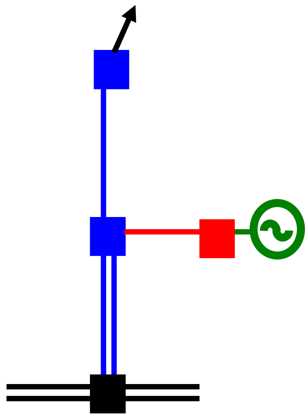
Example 3 shows a generation substation connecting to a second substation via a single circuit which is further connected to two different MITS substations. In this case, only the generation substation and the circuit connecting this to the second substation form a single radial spur used only for connecting generation to the MITS. The second substation and both the local circuits connecting this to the MITS substations do not form part of the spur as these parallel the MITS.

Example 4



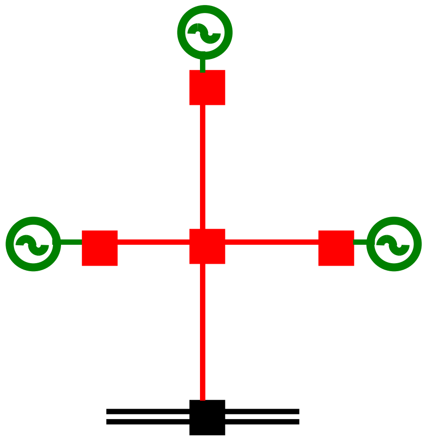
This example is identical to Example 3 with the exception that generation connects to the second substation. This makes no difference to the assets that form a radial spur used only for connecting generation to the MITS.

Example 5



This example shows a radial circuit that facilitates both generation and demand. The separate demand and generation substations connect via to a substation via a single circuit which in turn connects to a single MITS substation via a double circuit. In this scenario the generation substation and the single circuit connecting to the intermediatary substation form a radial spur used only for connecting generation to the MITS.

Example 6



Example 6 shows three generation substations connecting into a feeder substation via single circuits which then connects to a MITS substation. In this example, all of the local assets from the generation substations up to the MITS substation form a radial spur used only for connecting generation to the MITS. It is worth noting that as no local substation charge is levied for the feeder substation, no charges relating to this would be removed from the annual average transmission charge in this example.

Annex 5 – Workgroup Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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

Please send your responses by **23 January** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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

Respondent:	Cem Suleyman (cem.suleyman@drax.com)
Company Name:	Drax Power Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Overall, the Workgroup has developed a workable solution to the defect identified. However, we consider that the 'current' Original could be further improved if additional notice for market participants can be incorporated into the solution. The major concern we have with the current proposal is that the time between: a) the forecast made to set the G:D split; and b) the setting of final tariffs is around three months. A longer notice period would be helpful to ensure that market participants have greater predictability of TNUoS tariffs. This would then ensure any risk premium associated with the variability of TNUoS tariffs is kept to a minimum. This should ensure that consumers do not pay more than they need to and that they are not presented with unwelcome costs at relatively short notice. The time period between setting final 2015/16 TNUoS tariffs and the potential implementation of the Modification is not conducive to providing satisfactory notice to market participants. However, we recognise that the nature of the EC Regulation, in conjunction with the limited time available to develop the Modification, means the lack of notice, at least initially, is unavoidable. Nevertheless, we believe that the notice period in future years beyond 2015/16 could be increased so that the G:D split is set three full charging years in advance. For example, when the

	forecast is made in December 2014 it should look forward at least three years (to charging year 2018/19) and ensure a G:D split is set which is compliant with the EC regulation in all the TNUoS charging years forecast. This should improve the predictability and reduce the volatility of TNUoS charges. The workgroup will need to work through a longer term forecast option in more detail (for example considering whether additional bandwidth is required), but we believe that there is merit in adopting a longer term approach. We also suggest that from National Grid's next TNUoS tariff forecast update, including the Condition 5 Statement, forecasts are made which are compatible with the EC Regulation. This will further aid tariff predictability and provide market participants and consumers early visibility.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	Yes. The proposed Original better meets the Applicable CUSC objectives (ACO). In particular, the Original better facilitates ACO (c), because the Modification will ensure compliance with the EC Regulation and thus properly takes account of the developments in transmission licensees' transmission businesses. We consider the Original to be neutral against ACO (a) and (b). However, improvements to the Original (by providing longer notice periods to improve tariff predictability) could represent an improvement against ACO (a), at least relative to the 'current' Original (please see our answer to the above question for more detail).

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.**	Yes.
2	**Do you have any other comments?**	No.
3	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP224

Q	Question	Response
4	**Do you believe that the Workgroup has considered all potential interpretations of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?**	Yes.
5	**Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?**	No. We agree with the opinion that the wording of the exclusion within the EC Regulation is ambiguous in defining whether local charges or elements of the local charge may be excluded from the calculation of the annual average transmission charge. This being the case, we consider that as the intention of the Modification is to ensure compliance with the EC Regulation, it is prudent to include all Local Generation TNUoS Charges in the calculation. This is because the current permitted range of average charges (€2.50/MWh to €0/MWh) results in an asymmetric risk of non-compliance. Assuming that all local charges are included in the calculation and it subsequently transpires that some or all local charges should have been excluded, the UK will still be complying with the range of average charges. Although this could potentially be considered to be 'over compliance', i.e. setting the G:D split so that average TNUoS charges are less than is strictly necessary, essentially being much less than £2.50/MWh. We note that in any case this is not the major issue. Costs to consumers will not increase as a result of 'over compliance', but rather due to limited notice periods. However, in the opposite scenario, where all or some local charges are excluded from the calculation and it subsequently transpires that local charges should have been included, the UK is more likely to be failing to comply with the average range of charges. As such, including all local charges in the calculation is a lower risk option from a compliance perspective as the average charge floor is (currently) €0/MWh.

Q	Question	Response
6	**Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?**	Yes. Also please see answer to question 5.
7	**Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?**	Yes. The use of a bandwidth takes account of the forecasting uncertainty inherent in the annual average transmission charge calculation. The bandwidth thus represents an additional protection in ensuring compliance with the EC regulation. The calculation of the bandwidth (7%) is as objective a method as is likely to be available. However, consideration of increasing the bandwidth may be needed if a longer term approach to setting the G:D split is adopted (please see our answer to the first question in this response for more details).
8	**Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?**	No. We note that in practice the maximum allowed revenue will rise steeply in future years, meaning it is unlikely that in practice the G:D split could revert to its current 27:73 ratio following a change to the split. However, we still consider that there should be no automatic change back to the 27:73 split. This is for two main reasons. Firstly, allowing the G:D split to revert to the 27:73 ratio is likely to add additional volatility to TNUoS charges. As market participants will have to countenance symmetrical movements in the G:D split this raises the possibility of additional risk premia being included into consumer bills. Secondly, the purpose of the Modification is to ensure compliance with the EC Regulation. The current range of allowed average charges is €2.50/MWh to €0/MWh. Therefore, it is only important that the average charge in a year is within this range; it does not have to be as close to €2.50/MWh as possible. As such, in the interests of reducing TNUoS tariff volatility it is preferable that the G:D split does not automatically revert to the existing 27:73 ratio.

CUSC Workgroup Consultation Response Proforma

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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

Please send your responses by **23 January** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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

Respondent:	Paul Mott
Company Name:	EDF Energy
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The consultation effectively explores how to comply with regulation EC 838/2010, and thoroughly considers the appropriate treatment within the capped charges, of local circuit charges.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	Yes, applicable CUSC charging objective (b), cost-reflectivity, is indirectly relevant in that EC Regulation 838/2010 requires that TNUoS costs be recovered in a different ratio, where it has effect, than 27/73, between suppliers and generators. The modification appears neutral against applicable CUSC charging objective (a), on competition. On the face of it the modification appears neutral against applicable CUSC charging objective (c), on “developments in transmission licensees' transmission businesses” – however, as we don’t have a charging objective relating to European regulations, conventional wisdom is to consider that compliance with European regulations better facilitates (c). There are, as yet, no official alternatives. As to the unofficial possibilities for alternatives, we do support the interpretation of the regulation that entails including all Local TNUoS charges in the capped annual average generation TNUoS charges, in line with the legal advice received by the workgroup. We are not inclined to support the potential “ratchet” alternative

	whereby, if the cap "bites" in a given year so that generation TNUoS falls below 27% as a result of EC 838/2010 in a given year, that percentage should be maintained even if EC 838/2010 would not have capped charges in subsequent years. The regulation only requires that the cap should be applied in each year as required. The "ratchet" interpretation seems unlikely to be relevant unless the cap in EC 838/2010 were to be set to a higher number, which is not the most obvious direction of travel. We are aware that the ratchet option is said by its proponents to aid tariff stability, but we are not currently convinced. However, we should like to strongly emphasise the need for excellent advance information on TNUoS tariffs, as affected by CMP224, as advance knowledge of the level of tariffs, ideally 2+ years ahead, is key to all TNUoS-paying businesses. We would support the potential alternative that entails the application of an additional bandwidth to manage the risk of potential inadvertent breaches (due to exchange rate fluctuations and other effects that vary from ex-ante expectations). The merit of this approach lies in minimising the pressure for zero-notice in-year TNUoS adjustments – these would be very destabilising and would add risk for Suppliers and, where passed-through by Suppliers under contractual clauses, to some customers. For reference, the charging Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission

	businesses.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.**	We agree that if implemented, the proposal should come into effect prior to the start of the next charging year after Ofgem's decision, providing that Ofgem's decision is made by the 30th November preceding that charging year (i.e. a minimum of four months notice). We do not foresee a need for any special transitional arrangements for CMP 224
2	**Do you have any other comments?**	No
3	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP224

Q	Question	Response
4	**Do you believe that the Workgroup has considered all potential interpretations of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?**	Yes

Q	Question	Response
5	**Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?**	No
6	**Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?**	Yes
7	**Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?**	Yes
8	**Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?**	No. However, we should like to strongly emphasise the need for excellent advance information on TNUoS tariffs, as affected by CMP224, as advance knowledge of the level of tariffs, ideally 2+ years ahead, is key to all TNUoS-paying businesses.

CUSC Workgroup Consultation Response Proforma

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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

Please send your responses by **23 January** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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

Respondent:	*Guy Phillips, (guy.phillips@eon-uk.com)*
Company Name:	*E.ON UK plc*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Given the ambiguity of the first exclusion in the Regulation, alongside the ACER review of the limits in anticipation of a decision by the European Commission later in 2014, we believe it is appropriate for the Authority to be presented with two options; the original proposal that includes local charges and an alternative that excludes them. This is in order to enable the Authority to form its own opinion on what was intended by the Regulation and what is in the best interest of the GB consumer when coming to a decision on the Modification Proposal.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are

	made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. Both the Original and potential Working Group alternative, addressing the issue of local charges equivalence to charges for connection, ensure that the transmission licensee will satisfy the requirements of European legislation.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.**	Yes.
2	**Do you have any other comments?**	No.
3	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP224

Q	Question	Response

Q	Question	Response
4	**Do you believe that the Workgroup has considered all potential interpretations of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?**	Yes.
5	**Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?**	Yes. We support the initial view of the Working Group that option iv) in Table 1 could and indeed should be taken forward as a Working Group alternative. We put this forward for the reasons given in response to question 6 below.
6	**Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?**	No. The Regulation allows for the exclusion of 'charges paid by producers for physical assets required for connection to the system or the upgrade of the connection'. The Regulation provides no further clarity or definition as to the nature of the assets, the boundary of the system, the relevant charges for the assets, how they are defined, calculated or levied. It is therefore equally possible to conclude that a subset of TNUoS charges paid by specific producers in relation to specific assets used by them and required for connection to the system could be excluded from the calculation of the annual average transmission charge. The legal opinion states that excluding local charges leaves scope for challenge to the (GB) charging regime. Given the legal opinion also recognises that it is not clear on the face of the EC Regulation where the distinction between connection and network charges should be drawn; it is legitimately arguable that a counter challenge could be raised where network charges for assets that could be construed as connection assets and that the charges are not being excluded.

Q	Question	Response
7	**Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?**	No, as this adds a further artificial limit to the cap set by European law. In setting charges the Member State needs to consider that if they have been determined in accordance with Good Industry Practice and that there is the potential mechanism to rectify any breach; whether through a mid-year tariff change, or by adjusting the charges in the following charging year to rectify any breach in the first three months of the calendar year; what the likelihood of any enforcement action by the Commission would be, if any.
8	**Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?**	Yes. The 27:73 split has been a long standing feature of the GB charging methodology, deemed necessary to ensure cost reflectivity and that there is an appropriate share of the cost of the transmission system borne between generation and demand. This principle should be maintained as the baseline for those years when the cap is not exceeded.

CUSC Workgroup Consultation Response Proforma

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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

Please send your responses by **23 January** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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

Respondent:	Frank Gordon fgordon@r-e-a.net
Company Name:	Renewable Energy Association
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Whilst it should be taken as read that the average generation TNUoS charges must not breach the allowed EU range the proposed sticking plaster merely avoids or delays what should really be addressed namely facilitation competition by moving the G / D split in Great Britain to as near as possible the single market average which is perfectly allowable whilst staying within the currently permissible range for Great Britain. For the avoidance of doubt this could be done looking at only total TNUoS charges if desired as this would ensure compliance with the regulation as well as improving competition between Great Britain and the rest of the single EU market. Ideally the totality of transmission related costs on generators should be harmonised. We recognise that this is a more complicated task but make the point that taking all transmission related costs into account and implementing total cost harmonisation with the EU average would reduce GB TNUoS costs even further than just harmonising TNUoS costs with the EU average. Implementing the latter would therefore be a first step towards harmonising total transmission related costs to be met by generation between Great Britain and the EU average.

	Renewable generators in several EU countries enjoy transmission and related benefits compared to non renewable generation in those countries and this increases further the competitive disadvantage that renewable generation in Great Britain faces compared to renewable generation in some other parts of the single market. The Renewable Energy Association has never argued for any non cost reflective preferential treatment against non renewable generation – we should not however face unfair competition due to a different allocation of transmission related costs against the generality of generation in other parts of the single market.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	No. Objectives b and c are irrelevant. Whilst the proposal would ensure that the EU regulation was complied with it recognises / accepts that there will continue to be a difference in transmission charge burden between generators in Great Britain and those in other parts of the single market. As such it does nothing to further the facilitation of competition in generation. For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.**	We have no comments to make on the proposed implementation.
2	**Do you have any other comments?**	No
3	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No *If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the*

Specific questions for CMP224

Q	Question	Response
4	**Do you believe that the Workgroup has considered all potential interpretations of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?**	The wording is such that there can be no single unchallengeable interpretation of it. In particular "upgrade of the connection" could have a large number of interpretations.

[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Q	Question	Response
5	**Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?**	No. If one were to review all transmission related charges (including losses) paid by generators and compare them to the average levels in the rest of the single market one would conclude that the competitive disadvantage of GB generation is greater than that derived from total TNUoS charges alone so excluding these components of TNUoS charges from the comparison would be moving even further away from a fairly competitive single market.
6	**Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?**	Yes but for other reasons (see above) as well as the legal opinion.
7	**Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?**	Anything that could bring the burden closer to the single market average would be welcome.
8	**Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?**	We would rather that any capping is used as a staging post to reducing the burden to the EU average.

CUSC Workgroup Consultation Response Proforma

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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

Please send your responses by **23 January** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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

Respondent:	*Jonathan Wisdom – jonathan.wisdom@npower.com* *07584 491508*
Company Name:	*RWE npower ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Although we understand that European legislation is driving this arbitrary €2.50/MWh level, it does not seem to take into account individual systems and costs that apply in each different nationality. Therefore understanding the reasons to approve the change other than for purely European compliance is difficult and is hard to reconcile with the applicable CUSC modification objectives.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; **No. This will decrease transparency and not give confidence in charges and tariff forecasts as additional volatility will be possible. Furthermore, continual reduction of the Transmission charges for generation in line with Europe will erode any UK Specific locational signals over time.** (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); **No. This move allows the share of charges applied to Generation to be determined by a process that is removed from the machinations of the UK transmission network.** (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. **This development should have been anticipated. Inflicting short term change on the market through a lack of anticipation is not acceptable, especially since a new licence has recently been agreed which disallows mid-year tariff changes. (NG comment that mid year changes are still allowed, with the normal 150 or however many days notice)**

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.**	No. We believe that additional notice is required to enable the market to make commercially appropriate decisions. Currently Suppliers will be contracting with customers beyond April 2015 and will therefore not be able to take into account a change to TNUoS charges of this magnitude. Also customers will have budget considerations that extend beyond this period and disturbance to these is not in their interests. We also do not support any attempt at mid-year tariff changes. Our suggestion is that notice is given that a decision before March 2015 will result in changes in April 2017, decision by March 2016 results in changes in April 2018 in a similar fashion to the proposal for CMP201. This was seen as the minimum notice period for CMP201 and as this change is of a similar nature (ie cost transfer from one set of parties to another) the same principles should be applied. We also do not accept the volatility that this proposal introduces and believe that NGET should publish their percentage sharing factors at least 2 years before they are applied to ensure that the market is receiving effective price signals. We understand this may mean that conservative estimates are used for the proscribed €/MWh level that will need to be adhered to. However, we believe that the increased certainty in costs that will result will more than outweigh any potential additional costs that are incurred by demand customers. There needs to be some limit to this 'conservative' estimate, maybe constrained to the current variability of NGC 'high scenario' tariff against base forecast and range of current to Bank of England exchange rate forecasts. If the average tariff still breaches the threshold, then all tariffs charged should to be scaled back accordingly, changes to the sharing factor published with stated notice period and the lost income recovered through under-recovery included in revised tariffs for the tariff year after the following.

Q	Question	Response
2	**Do you have any other comments?**	This €2.50/MWh limit has been published since 2010. We see it as inappropriate for NGET to cause market disturbance through a change they could have anticipated significantly earlier and prepared the UK market for. Minor changes in the split between Generation and Demand could have been phased in over time particularly from the publication of the original RIIO T-1 business plans as this would have indicated the likely cost levels that NGET would have been expecting over the next 8 years. Appropriate change could have been managed and communicated from this point. It is not acceptable that short notice changes to tariffs and particularly to the end prices that customers pay occur because of a development that NGET should have taken into account and communicated more effectively.
3	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*We propose the attached with a different implementation timescale.*

Specific questions for CMP224

Q	Question	Response
4	**Do you believe that the Workgroup has considered all potential interpretations of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?**	Yes

Q	Question	Response
5	**Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?**	We believe that this should be considered as a mechanism to ensure charges remain stable. Option iv demonstrates that only the radial spur connections need to be considered as these make up the significant portion of the local costs. We believe that option iv should be taken forward in conjunction with this proposal for changing the sharing factor, such that the sharing factor can be used as a longer term control to be brought into action should the European Commission overturn this (Table 1 option iv) interpretation of the rules.
6	**Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?**	No, we believe that these should be excluded as described in our response to Q5.
7	**Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?**	We believe that NGET should publish their percentage sharing factors at least 2 years before they are applied to ensure that the market is receiving effective price signals. We understand this may mean that conservative estimates are used for the proscribed €/MWh level that will need to be adhered to. However, we believe that the increased certainty in costs that will result will more than outweigh any potential additional costs that are incurred by demand customers.
8	**Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?**	Yes with appropriate notice given as said above.

CUSC Workgroup Consultation Response Proforma

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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

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Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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

Respondent:	*James Anderson. Phone: 0141 614 3006* *email:james.anderson@scottishpower.com*
Company Name:	*ScottishPower Energy Management Ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	ScottishPower supports the introduction of a cap on the proportion of TO Allowed Revenue recovered through GB generation transmission charges to ensure that the limit within EC Regulation 838/2010 Part B is not breached. We believe that in assessing compliance with the Regulation, the existing definition of Connection Assets within the GB Codes should be used and that TNUoS charges associated with Local Assets should be included in the calculation.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is

	reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.**	ScottishPower supports the introduction of a cap on the proportion of TO Allowed Revenue recovered through GB generation transmission charges to ensure that the limit within EC Regulation 838/2010 Part B is not breached. In assessing compliance with the EC Regulation, no proportion of Local Asset charges should be excluded. Setting of the cap on the proportion charged to GB generation should be based on a forward-looking assessment that includes sufficient "headroom" to ensure that the EC Regulation is not breached.
2	**Do you have any other comments?**	No
3	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*No.*

Specific questions for CMP224

Q	Question	Response

Q	Question	Response
4	**Do you believe that the Workgroup has considered all potential interpretations of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?**	Yes. ScottishPower believes that the Workgroup has considered all potential interpretations of "connection assets" referred to within the EC Regulation.
5	**Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?**	No. ScottishPower believes that there is a clear definition of Connection Assets and their associated Connection Charges within the GB Codes and that this existing split should be used in assessing compliance with the EC Regulation.
6	**Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?**	Yes. Based upon the legal opinion from National Grid it would be sensible to include Local Asset charges in the calculation of annual average transmission charges. There is no clear justification for moving away from the existing definition of Connection Assets in the GB Codes and to do so would potentially be subject to challenge with consequential implications from enforcement action by the EU.
7	**Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?**	Yes. Due to the variability of a number of elements within the calculation of annual average generation transmission charges, the assessment of any cap should be forward-looking and should provide sufficient "headroom" or "bandwidth" to ensure that breaches of the EC Regulation do not occur. Such an approach would potentially assist in mitigation should any breach occur and potentially reduce any enforcement action. ScottishPower agrees with the Workgroup's assessment (4.54) that a bandwidth of 7% should be used.

Q	Question	Response
8	**Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?**	European Commission Regulation 838/2010 (10) states that "average charges for access to the network in Member States should be ***kept within a range*** which helps ***to ensure that the benefits of harmonisation are realised***". National Grid should not seek simply to comply with the Regulation by setting generation tariffs just below the cap but to move towards harmonisation of tariffs to ensure the removal of barriers to trade and facilitate more efficient competition in generation across member states. While the stated objective of this Modification is to achieve ***compliance*** with the EC Regulation, ScottishPower believes that this lacks the ambition to achieve the ***spirit*** of the Regulation which is a move towards tariff harmonisation. To this end, not allowing the G/D split to revert to 27:73 would allow a gradual move towards harmonisation and would also provide additional certainty to both generation and demand TNUoS payers of the future direction of any change in the G/D split.

CUSC Workgroup Consultation Response Proforma

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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

Please send your responses by **23 January** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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

Respondent:	*Colin Prestwich*
Company Name:	*SmartestEnergy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We not not approve of tinkering with the methodology to avoid a breach of a cap and believe a more radical review of the 73/27 split is required sooner rather than later.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We do not believe that the proposal better facilitates any of the Applicable CUSC objectives. Indeed, random caps can only hinder competition and clearly do not reflect costs appropriately. For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale,

	distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.**	We do not support to proposed implementation approach. Para 3.7 of the document states: "The application of this cap will allow National Grid to reduce the overall TNUoS revenue collected from generation Users in GB. Therefore, the G/D split ratio may be modified when it is forecast that adherence to 27% for generation revenue does not fall within the range (of € zero to €2.5 /MWh) specified by the EC Regulation." The problem here is the word forecast and it is possible that having set the percentage the outturn is greater and a breach of the EU legislation will have taken place. This is odd since "the main driver for this Modification Proposal is to ensure this limit is not breached and therefore to ensure the GB charging arrangements remain compliant with European Legislation."

Q	Question	Response
2	**Do you have any other comments?**	It would clearly be more sensible to address the 27/73 split on an enduring basis. Whilst we are not in favour of change for the sake of it, it is important to gauge exactly how matters are likely to develop in Europe and, if the cap is likely to be breached GB should consider moving to a 100/0 split. In the long run this will be better for customers because the cost of wholesale power would reduce to compensate for the increase in TNUoS on the demand side. The uncertainty over whether the cap will be breached will lead suppliers to build in a premium to their tariffs which long term customers will have to pay for.
3	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP224

Q	Question	Response
4	**Do you believe that the Workgroup has considered all potential interpretations of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?**	Yes
5	**Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?**	No. Even if any of these costs could be deemed to be applicable to Connection they clearly are currently not. This modification is not concerned with changing the way NGT's costs are recovered.

Q	Question	Response
6	**Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?**	Yes
7	**Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?**	No. The past is no indicator of the future.
8	**Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?**	No/indifferent. If the EU is going to impose random caps then perhaps the rationale for the 27:73 split should be revisited sooner rather than later. However, it is not appropriate to tinker with it on an occasional basis just to avoid the cap. We are not convinced that there is any more or less certainty by either reverting back to 27:73 or keeping the level.

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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Respondent: Garth Graham (garth.graham@sse.com)

Company Name: SSE

Please express your views regarding the Workgroup Consultation, including rationale. (Please include any issues, suggestions or queries)

We express our views regarding this Workgroup Consultation (including our rationale) in our responses to the specific questions posed in this consultation by the Workgroup (as set out below).

However, we do have some additional observations:-

i) since the calculation approach currently **includes** local charges, it would look odd to the European Commission to find that GB, when faced with breaching the €2.5 upper limit, changes the calculation approach itself. Furthermore since it is a 'Regulation' it is binding on all relevant parties; and not just the Member State; including National Grid and Ofgem and it would be open to anyone raising the issue with the European Commission.

ii) since the interpretation can only be tested at the European Commission, it would seem sensible to err on the safe side, continue with existing calculation approach and cap GB average annual transmission charges at less than €2.5/MWh. Doing otherwise would seem to highlight the issue and ask for it to be taken to the European Commission.

ii) has anyone considered the position that Ofgem could put National Grid in if they approve a calculation approach that would put National Grid in breach of the Regulation?

Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.

As we understand the CMP224 Original proposal, as set out by the Proposer at the 6th December 2013 Workgroup meeting, it means that all local charges currently applied, by National Grid, to generators would be **included** in the calculation of the annual average transmission charges paid by generators in GB.

Given this we believe that CMP224 (as its currently set out by the Proposer) does better meet Applicable CUSC (Charging) Objective (c) in so far as it is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, and as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. Furthermore, it would also be consistent, in our view, with the terms of EU Regulation 838/2010 Part B (the 'Regulation'), and in particular paragraphs 1, 2 (1) and 3 thereof.

However, if at a later stage in the proceedings with this Modification (as per the Proposer Ownership principle) the Proposer were to redefine CMP224 Original so as to **exclude** some or all elements of the local charges currently applied, by National Grid, to generators in the calculation of the annual average transmission charges paid by generators in GB then this would, in our view, mean that CMP224 Original (in this scenario[1]) would not better meet Applicable CUSC (Charging) Objective (c) nor would it be consistent, in our view, with the terms of EU Regulation 838/2010 Part B, and in particular paragraphs 1, 2 (1) and 3 thereof.

Standard Workgroup consultation questions

1 Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.

We note the proposed implementation timescale set out in paragraph 7.1 and, at this stage, we concur in principle with what is being proposed.

We note that the Workgroup has considered the potential implementation issues that could arise with CMP224 given that the date of any change in the €2.5 upper limit (which is subject to a review by ACER at the moment) may come into effect on 1st January 2015; i.e. during the (GB) Charging Year 2014/15. Of the two options set out in paragraph 7.8 we would, at this stage, support the second option as this should ensure that, over the calendar year 2015, the average annual transmission charges paid by GB generators will be in compliance with Regulation (all be it that it may not do so over the first three months up to 31st March 2015).

2 Do you have any other comments?

[1] Or any Workgroup Alternative(s), if raised, which excluded some or all local elements.

We are mindful that CMP224 is directly related to the terms of EU Regulation 838/2010 (Part B). A key element of that Regulation is the matter of harmonisation of transmission charges amongst the Member States. Currently, according to the Regulation, 21 of the Member States have generation transmission charges that are within a range €0 - €0.5 with the remaining six countries having a higher range of either (i) €0-€1.2 (Denmark, Sweden and Finland) or (ii) €0-€2 (Romania) or (iii) €0-€2.5 (UK and Ireland).

We are aware of a recent detailed independent study[2] undertaken into generator transmission charges across four countries in Europe[3] on the matter of harmonisation. The conclusions of that report are shown below and these clearly show that harmonisation of generator transmission charges is the economically correct thing to do.

> *A lack of harmonisation or changes to generator transmission charges which reduce harmonisation between countries for reasons other than to reflect differences in forward looking costs can have three different types of impact on economic welfare.*
>
> *First, they can result in distorted operational decisions. If a low cost generator in country A faces high transmission charges, it may not produce electricity, with demand instead being satisfied by a higher cost generator in country B where transmission charges are lower. This reduces economic welfare, because demand is not met using the lowest cost combination of resources.*
>
> *Second, they can result in distorted investment decisions. If generator transmission charges are high in country A, investors may opt to locate in country B and export power to country A. This would be inefficient if other aspects of cost (e.g. land, labour) were higher in country B.*
>
> *Third, they may increase investors' perceptions of risk. If generation transmission charges increase in country A for reasons unrelated to cost reflectivity and generators cannot pass through all of the cost increase, it will reduce returns on investment. Investors may take the view that the same or similar changes could take place in the future and will therefore demand a higher return on investment to compensate this regulatory risk. This will tend to reduce investment in the country's power sector, resulting in demand not being met in the most efficient way (e.g. overreliance on older, less efficient plant). It will also tend to result in under-consumption of electricity over time (e.g. through larger, more mobile customers locating in other markets).*

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[2] The study has been provided to us in confidence. We have provided the reference etc., to the Authority under separate cover in response to their recent consultation on "Impact assessment on CMP201 - proposal to remove balancing charges from generators".

[3] France, Germany, Belgium and the Netherlands.

We endorse these conclusions. It is clear to us that the higher range of average annual transmission tariffs paid for by generators in GB (plus Northern Ireland and Ireland) are having a distorting effect on the GB[4] generation market.

In our view rather than seeking to 'fiddle' with the way the calculation is done (to seek to give the 'appearance' that GB is complying with the current €2.5 upper limit) as some stakeholders appear to want, more effort should be given to seeking to reduce the €2.5 limit itself to bring the transmission charges paid by GB[5] generation more into line with the rest of continental Europe with whom, in a very short space of time, we will be actively coupled with via the planned 'Target Model' arrangements and the associated European Network Codes (such as those covering Capacity Allocation & Congestion Management, Forward Capacity Allocation and Balancing).

It appears to us that some stakeholders seem to believe that CMP224 should be used to 'gerrymander' the average annual transmission tariff figure paid by generators in GB such that they seem (for the sake of 'appearance) to remain within the €2.5 upper limit (even when, in reality, they do not).

The way this 'gerrymandering' manifests itself is in the efforts to seek to exclude various charges paid by generators from the calculation of the annual average transmission charges paid by (GB) generators. This is most clearly shown by the various options set out in Table 1 of the Workgroup consultation.

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

No.

4 Do you believe that the Workgroup has considered all potential interpretations of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?

Yes. In our view the interpretation of "charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010 is clear – it does not mean excluding some or all charges for the local network.

5 Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?

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[4] plus Northern Ireland and Ireland
[5] plus Northern Ireland and Ireland

No. In our view the correct legal interpretation of EU Regulation 838/2010 Part B, and in particular paragraphs 1, 2 (1) and 3 thereof, is that all local generation TNUoS charges should be **included** within the annual average transmission charges as part of defining a cap on the proportion of TNUoS charges paid by generation in GB under the proposed solution. We have provided compelling reasons as to why this should be the case in our answer to Question 6 below.

6 Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?

In our view it would be wholly sensible based on (a) National Grid's summary legal opinion and (b) our view of the legal matters that arise from CMP224 to **include** all assets subject to local TNUoS charges within the calculation of the annual average transmission charges when calculating the GB position with respect to €2.5 limit.

In our view this would be consistent with the terms of EU Regulation 838/2010 Part B, and in particular paragraphs 1, 2 (1) and 3 thereof.

The Regulation imposes a limit on the annual average transmission charges which are paid by producers (generators) in each Member State. The issue that the CMP224 Workgroup has been considering relates to the interpretation of what constitutes "transmission charges" within the Regulation and the exclusions therefrom.

We considers that the CUSC is the most relevant document to consult when seeking to determine, in the context of GB, the practical application of Regulation 838/2010 Part B as it deals, explicitly, with the connection to and charges arising from the connection to and use of the transmission system in GB.

In order to assist the Workgroup to consider this matter, National Grid provided (at the first Workgroup meeting) an illustrative example of the GB electricity transmission system. The relevant slide is number 12 ('Local Charges').

It is common ground amongst the Workgroup members that (i) the red 'Local' network and the black 'Wider' network (shown on slide 12) are, collectively, known as the National Electricity Transmission System (or 'NETS') and that the 'Wider' network, as illustrated on the slide, is the Main Integrated Transmission System (or 'MITS') and that (ii) the green Generator specific assets are neither part of the NETS or MITS.

Part B of the Regulation includes the following pertinent passages:-

> *"Annual average transmission charges paid by producers is annual total transmission tariff charges paid by producers divided by the total measured*

energy injected annually by producers to the transmission system of a Member State." [Statement 1]

"For the calculation set out at Point 3[Statement 3], transmission charges shall exclude:

charges paid by producers for physical assets required for connection to the system or the upgrade of the connection" [Statement 2]

"The value of the annual average transmission charges paid by producers shall be within a range of 0 to 0,5 EUR/MWh, except those applying in ...... Great Britain.... Annual average transmission charges paid by producers in ... Great Britain... shall be within a range of 0 to 0,25 EUR/MWh..." [Statement 3]

[emphasis added]

It is common ground amongst the Workgroup members that it is necessary for GB to ensure that the average transmission charges paid by generators in GB remain within a range of €0-€2.5 (as per paragraph 3 [Statement 3] of Part B of the Regulation) or such other figure as maybe amended from time to time by the European Commission.

The question which has arisen within the Workgroup is what item(s) does or does not make up the definition of "transmission charges" and in particular which aspects, if any, of those charges should be treated as **excluded** as '*charges*' for '*connection'* to '*the system*', as set out in Statement 2.

We believe there are clear reasons to **include** (rather than **exclude**) all assets subject to local TNUoS charges within the calculation of the annual average transmission charges when calculating the GB position with respect to the €2.5 limit.

These reasons include:-

(a) It is our contention that it is possible to determine (in the context of GB) what is (i) meant by '*connection*', including by reference to the CUSC definition[6] of it and (ii) the '*system*', by noting that Statement 2 is written to ensure the calculation set out in Statement 1 is undertaken in order to determine the range set out in Statement 3 is not exceeded. Those who drafted the Regulation must have given specific consideration to what was included in the definition of "transmission charges" within each Member State and the GB system in particular, in order to arrive at the different caps provided for each Member State.

(b) It is our contention that it cannot sensibly be concluded that Statement 2 of the Regulation has no meaning within the GB system since the Regulation would, in effect, be rendered unenforceable. On the contrary, read in the context of both

[6] This is shown in Appendix 1 to this response.

Statement 1 and Statement 3, the only reasonable conclusion is that the '*system*' referred to in Statement 2 is one and the same as the '*transmission system*' in Statement 1.

(c) It is our contention that as the CUSC currently defines[7] (i) what is meant by 'Connection Charges' and (ii) that National Grid produces invoices and issues these to generators for the said 'Connection Charges' (in accordance with CUSC Section 2.14.1[8]) that it is possible today to complete the calculation required in Statement 2 by reference to said 'Connection Charges' paid by GB generators to connect to said '*system*' in GB.

(d) It is our contention that the section of the CUSC[9] which deals with "Connections" (Section 2) refers only to NETS[10] and does so on no less than 26 occasions, whilst there is (in Section 2) no reference to MITS. Therefore, it is contended that the only sensible interpretation is to view '*connection*', in a GB context, in terms of the '*system*' being the NETS (and not the MITS).

(e) Furthermore, it is our contention that the matter of where a generator connects to the '*system*' should be clear to National Grid as, for example, it was recently the subject of an opinion by the Authority in its decision letter of CAP189[11] where it was noted that:-

> *"A generator or a distribution network is generally connected to the transmission network through a substation to provide both protection and control to the transmission network. The substation assets form an electrical boundary. The CUSC (section 2.12) defines the standard boundary and sets out how ownership of the assets at the boundary is split between the connecting user and the National Electricity Transmission System (NETS) for different types of asset."*

The Authority's decision letter goes on to note that CAP189 was raised by National Grid itself (in July 2010) and that *"[t]he proposal seeks to amend the CUSC so that a user requesting a connection to the NETS through a GIS substation can elect to do so using either of two standard ownership boundaries*".

(f) It is our contention that National Grid has already set a precedent in how to undertaken the calculation in Statement 2 when it undertook that same calculation to inform the Authority's Project Transmit Technical Working Group as witnessed by its

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[7] This is shown in Appendix 1 to this response.
[8] This is shown in Appendix 1 to this response.
[9] This is shown in Appendix 1 to this response.
[10] 2.1.1 x**1**, 2.1.2 x**2**, 2.2.1 x**1**, 2.2.2 (b) x**1**, 2.2.3 x**1**, 2.2.4 x**2**, 2.3.1 x**2**, 2.3.2 x**2**, 2.4 x**1**, 2.5 x**1**, 2.7 x**1**, 2.12.1 (a) x**1**, 2.12.1 (b) x**2**, 2.12.1 (c) x**1**, 2.12.1 (d) x**1**, 2.12.2 x**1**, 2.13.7 x**1**, 2.13.11 (a) x**2**, 2.13.11 (b) (i) x**1** and 2.13.12 x**1.**
[11] http://www.nationalgrid.com/NR/rdonlyres/7BE14FC7-7AE6-409F-82F6-1A8A117D0B8B/51173/CAP189D.pdf

presentation[12] to that group in August 2011 and in particular slides 5, 6, 7, 9, 10 and 11 which were calculated, by National Grid, "*in accordance with the European Tarification Guidelines*"[13] .

For these reasons we strongly believe that the legal position is clear that it is appropriate for CMP 224 to be adopted such that all charges paid by producers for connection to the "local" network are **included** in the calculation of the "annual average transmission charges" for the purposes of Part B of the Regulation.

7 Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?

Yes. We note the Workgroup deliberations on option (c) outlined in paragraph 4.37 and explored, in detail, in paragraphs 4.43-4.56.

In our view there is a case for a bandwidth to be adopted to ensure that GB does not breach the Regulation. This, in our view is appropriate given the inherent variability of the three elements that go into calculating the annual average transmission charges paid for by GB generators; namely:-

i) the total level of generation output;
ii) TO Allowed Revenue; and
iii) the £/€ exchange rate.

Not having a bandwidth could lead to repeated breaching by GB of the limit (be that, as currently, €2.5 or some other higher or lower figure depending on the outcome of the ongoing ACER review and the European Commission determination). This would not be desirable, both in terms of compliance with the law but also in terms of the increase in regulatory risk that would arise if this were to happen as parties would be unsure what, if any, rectification to the GB transmission charges might be required to rectify the breach for the rest of the year in question.

8 Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?

Yes. Assuming there is no breach of the limit set in the Regulation then, in our view, it would appear correct to return to the situation we have today.

However, that having been said, we note the compelling economic case which we set out in response to our answer to Question 2 above that harmonisation of the annual

[12] https://www.ofgem.gov.uk/sites/default/files/docs/2011/08/transmit-wg-postmtg4_eu-tarification-guidelines.pdf
[13] page 9 of the group's minutes 18th August 2011
https://www.ofgem.gov.uk/sites/default/files/docs/2011/09/minutes---working-group-meeting-4-%28version-1.0%29.pdf

average transmission tariffs paid by generators in GB with those for neighbouring areas, such as Holland and France, is highly desirable. Given this we could see a case being made for the GB G:D split not reverting back to 27:73 if that would run counter to the creation and ongoing operation of the Internal Market in electricity.

Annex 1 CMP224 Legal aspects – extracts from relevant documents

[1] EU Regulations

COMMISSION REGULATION (EU) No 838/2010 [14]

of 23 September 2010

on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging

PART B

Guidelines for A Common Regulatory Approach to Transmission Charging

1. Annual average transmission charges paid by producers in each Member State shall be within the ranges set out in point 3.

2. Annual average transmission charges paid by producers is annual total transmission tariff charges paid by producers divided by the total measured energy injected annually by producers to the transmission system of a Member State.

For the calculation set out at Point 3, transmission charges shall exclude:

(1) charges paid by producers for physical assets required for connection to the system or the upgrade of the connection;
(2) charges paid by producers related to ancillary services;

(3) specific system loss charges paid by producers.

3. The value of the annual average transmission charges paid by producers shall be within a range of 0 to 0,5 EUR/MWh, except those applying in Denmark, Sweden, Finland, Romania Ireland, Great Britain and Northern Ireland.

The value of the annual average transmission charges paid by producers in Denmark, Sweden and Finland shall be within a range of 0 to 1,2 EUR/MWh.

Annual average transmission charges paid by producers in Ireland, Great Britain and Northern Ireland shall be within a range of 0 to 2,5 EUR/MWh, and in Romania within a range of 0 to 2,0 EUR/MWh.

[14] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF

4. The Agency shall monitor the appropriateness of the ranges of allowable transmission charges, taking particular account of their impact on the financing of transmission capacity needed for Member States to achieve their targets under the Directive 2009/28/EC (1) of the European Parliament and of the Council and their impact on system users in general.

5. By 1 January 2014 the Agency shall provide its opinion to the Commission as to the appropriate range or ranges of charges for the period after 1 January 2015.

DIRECTIVE 2009/72/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL[15]
of 13 July 2009
concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC

Article 2

3 'transmission' means the transport of electricity on the extra high-voltage and high-voltage interconnected system with a view to its delivery to final customers or to distributors, but does not include supply;

4 'transmission system operator' means a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity;

[2] CUSC

Section 11 – Definitions[16]

"**Attributable Works**"

those components of the **Construction Works** which are required (a) to connect a **Power Station** which is to be connected at a **Connection Site** to the nearest suitable **MITS[17] Node**; or (b) in respect of an **Embedded Power Station** from the relevant **Grid**

[15] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF

[16] **http://www.nationalgrid.com/NR/rdonlyres/FC669161-44F9-4FE6-90A2-1B59CC855107/62918/CUSCSection11_v155_CMP218_16_Oct_2013.pdf**

[17] References to 'MITS' and 'NETS' are highlighted here for ease of identification.

Supply Point to the nearest suitable **MITS Node** (and in any case above where the **Construction Works** include a **Transmission** substation that once constructed will become the **MITS Node**, the **Attributable Works** will include such **Transmission** substation) and which in relation to a particular **User** are as specified in its **Construction Agreement**;

"Connection"

a direct connection to the **National Electricity Transmission System** by a **User**;

"Connection Application"

an application for a **New Connection Site** in the form or substantially in the form set out in Exhibit B to the **CUSC**;

"Connection Boundary"

shall be the boundary defined by Paragraph 14.2.6 of the Statement of the Connection Charging Methodology;

"Connection Charges"

charges made or levied or to be made or levied for the carrying out (whether before or after the date on which the **Transmission Licence** comes into force) of works and provision and installation of electrical plant, electric lines and ancillary meters in constructing entry and exit points on the **National Electricity Transmission System**, together with charges in respect of maintenance and repair of such items in so far as not otherwise recoverable as **Use of System Charges**, all as more fully described in the
Transmission Licence, whether or not such charges are annualised, including all charges provided for in the statement of **Connection Charging Methodology** (such as **Termination Amounts** and **One-off Charges**);

"Connection Conditions" or "CC"

that portion of the **Grid Code** which is identified as the **Connection Conditions**;

"Connection Entry Capacity"

the figure specified as such for the **Connection Site** and each **Generating Units** as set out in Appendix C of the relevant **Bilateral Connection Agreement**;

"Connection Offer"

an offer or (where appropriate) the offers for a **New Connection Site** in the form or substantially in the form set out in Exhibit C including any revision or extension of such offer or offers;

"Connection Site"

each location more particularly described in the relevant **Bilateral Agreement** at which a **User's Equipment** and **Transmission Connection Assets** required to connect that **User** to the **National Electricity Transmission System** are situated. If two or more
Users own or operate **Plant** and **Apparatus** which is connected at any particular location that location shall constitute two (or the appropriate number of) **Connection Sites**;

"Connection Site Demand Capability"

the capability of a **Connection Site** to take power to the maximum level forecast by the **User** from time to time and forming part of the **Forecast Data** supplied to **The Company** pursuant to the **Grid Code** together with such margin as **The Company** shall in its reasonable opinion consider necessary having regard to **The Company's** duties under its **Transmission Licence;**

"MITS Connection Works"

means those **Transmission Reinforcement Works** (inclusive of substation works) that are required from the **Connection Site** to connect to a **MITS Substation** (and in the context of an **Embedded Power Station**, "connection site" shall mean the associated **Grid Supply Point** identified as such in the relevant **Bilateral Agreement**);

"National Electricity Transmission System" or "NETS"

the system consisting (wholly or mainly) of high voltage electric wires owned or operated by transmission licensees within **Great Britain** and **Offshore** and used for the transmission of electricity from one **Power Station** to a sub-station or to another **Power**
Station or between sub-stations or to or from any **External Interconnection** and includes any **Plant** and **Apparatus** or meters owned or operated by any transmission licensee within **Great Britain** and **Offshore** in connection with the transmission of electricity but shall not include **Remote Transmission Assets**;

"New Connection Site"

a proposed **Connection Site** in relation to which there is no **Bilateral Agreement** in force between the **CUSC Parties**;

"Site Specific Maintenance Charge"

the element of the **Connection Charges** relating to maintenance and repair calculated in accordance with the **Connection Charging Methodology**;

"Site Specific Requirements"

those requirements reasonably required by **The Company** in accordance with the **Grid Code** at the site of connection of a **Relevant Embedded Medium Power Station** or a **Relevant Embedded Small Power Station**;

"Termination Amount"

in relation to a **Connection Site**, the amount calculated in accordance with the **Charging Statements**;

"Transmission"

means, when used in conjunction with another term relating to equipment, whether defined or not, that the associated term is to be read as being part of or directly associated with the **National Electricity Transmission System** and not of or with the **User System**;

"Transmission Business"

the authorised business of **The Company** or any **Affiliate** or **Related Undertaking** in the planning, development, construction and maintenance of the **National Electricity Transmission System** (whether or not pursuant to directions of the Secretary of State made under section 34 or 35 of the **Act**) and the operation of such system for the transmission of electricity, including any business in providing connections to the **National Electricity Transmission System** but shall not include (i) any other **Separate Business** or (ii) any other business (not being a **Separate Business**) of **The Company** or any **Affiliate** or **Related Undertaking** in the provision of services to or on behalf of any one or more persons;

"Transmission Connection Assets"

the **Transmission Plant** and **Transmission Apparatus** necessary to connect the **User's Equipment** to the **National Electricity Transmission System** at any particular C**onnection Site** in respect of which **The Company** charges **Connection Charges** (if any) as listed or identified in Appendix A to the **Bilateral Connection Agreement** relating to each such **Connection Site**;

"Transmission Connection Asset Works"

in relation to a particular **User**, as defined in its **Construction Agreement**;

"Transmission Licensees Assets"

The Plant and Apparatus owned by Transmission Licensees necessary to connect the User's Equipment to the **National Electricity Transmission System** at any particular Connection Site in respect of which **The Company** charges Connection

"User's Equipment"

the **Plant** and **Apparatus** owned by a **User** (ascertained in the absence of agreement to the contrary by reference to the rules set out in Paragraph 2.12) which: (a) is connected to the **Transmission Connection Assets** forming part of the **National Electricity Transmission System** at any particular **Connection Site** to which that **User** wishes so to connect, or (b) is connected to a **Distribution System** to which that **User** wishes so to connect but excluding for the avoidance of doubt any **OTSUA**;

"User System"

any system owned or operated by a **User** comprising **Generating Units** and/or **Distribution Systems** (and/or other systems consisting (wholly or mainly) of electric lines which are owned or operated by a person other than a **Public Distribution System**
Operator and **Plant** and/or **Apparatus** connecting **Generating Units**, **Distribution Systems** (and/or other systems consisting wholly or mainly of electric lines which are owned or operated by a person other than a **Public Distribution System Operator** or **Non-Embedded Customers** to the **National Electricity Transmission System** or (except in the case of **Non-Embedded Customers**) to the relevant other **User System**, as the case may be, including any **Remote Transmission Assets** operated by such **User** or other person and any **Plant** and/or **Apparatus** and meters owned or operated by such **User** or other person in connection with the distribution of electricity but does not include any part of the **National Electricity Transmission System**;

Section 14 – Charging Methodologies[18]

Connection/Use of System Boundary

[18] http://www.nationalgrid.com/NR/rdonlyres/8FFA9408-9DC7-44C2-AF68-93E684A176D8/59890/CUSC_Section_14_v15combined_CMP203_1April2013.pdf

14.2.4 The first step in setting charges is to define the boundary between connection assets and transmission system infrastructure assets.

14.2.5 In general, connection assets are defined as those assets solely required to connect an individual User to the National Electricity Transmission System, which are not and would not normally be used by any other connected party (i.e. "single user assets").

For the purposes of this Statement, all connection assets at a given location shall together form a connection site.

14.2.6 Connection assets are defined as all those single user assets which:

a) for Double Busbar type connections, are those single user assets connecting the User's assets and the first transmission licensee owned substation, up to and including the Double Busbar Bay;

b) for teed or mesh connections, are those single user assets from the User's assets up to, but not including, the HV disconnector or the equivalent point of isolation;

c) for cable and overhead lines at a transmission voltage, are those single user connection circuits connected at a transmission voltage equal to or less than 2km in length that are not potentially shareable.

14.2.7 Shared assets at a banked connection arrangement will not normally be classed as connection assets except where both legs of the banking are single user assets under the same Bilateral Connection Agreement.

14.2.8 Where customer choice influences the application of standard rules to the connection boundary, affected assets will be classed as connection assets. For example, in England & Wales The Company does not normally own busbars below 275kV, where The Company and the customer agree that The Company will own the busbars at a low voltage substation, the assets at that substation will be classed as connection assets and will not automatically be transferred into infrastructure.

14.2.9 The design of some connection sites may not be compatible with the basic boundary definitions in 14.2.6 above. In these instances, a connection boundary consistent with the principles described above will be applied.

Section 2 – Connection[19]

[19] http://www.nationalgrid.com/NR/rdonlyres/D1B64625-6919-4001-A90A-62AAEAF1C56F/62916/CUSC_Section_2_CMP218_V112_16Oct_2013.pdf

2.12 PRINCIPLES OF OWNERSHIP

2.12.1 Subject to the **Transfer Scheme** or any contrary agreement in any **Bilateral Agreement** or any other agreement the division of ownership of **Plant** and **Apparatus** shall be at the electrical boundary, such boundary to be determined in accordance with the following principles:

In the case of air insulated switchgear:

(a) in relation to **Plant** and **Apparatus** located between the **National Electricity Transmission System** and a **Power Station**, the electrical boundary is at the busbar clamp on the busbar side of the busbar isolators on **Generators** and **Power Station** transformer circuits;

(b) save as specified in Paragraph 2.12.1(c) below, in relation to **Plant** and **Apparatus** located between the **National Electricity Transmission System** and a **Distribution System**, the electrical boundary is at the busbar clamp on the busbar side of the **Distribution System** voltage busbar selector isolator(s) of the **National Electricity Transmission System** circuit or if a conventional busbar does not exist, an equivalent isolator. If no isolator exists an agreed bolted connection at or adjacent to the tee point shall be deemed to be an isolator for these purposes;

(c) in relation to **Transmission Plant** and **Transmission Apparatus** located between the **National Electricity Transmission System** and a **Distribution System** but designed for a voltage of 132KV or below in England and Wales and below 132kV in Scotland, the electrical boundary is at the busbar clamp on the busbar side of the busbar selector isolator on the **Distribution System** circuit or, if a conventional busbar does not exist, an equivalent isolator. If no isolator exists, an agreed bolted connection at or adjacent to the tee point shall be deemed to be an isolator for these purposes;

(d) in relation to **Plant** and **Apparatus** located between the **National Electricity Transmission System** and the system of a **Non-Embedded Customer**, the electrical boundary is at the clamp on the circuit breaker side of the cable disconnections at the **Non-Embedded Customer's** sub-station; and In the case of metal enclosed switchgear, that is not **Gas Insulated Switchgear:**

(e) the electrical boundary will be the equivalent of those specified in this Paragraph 2.12.1 save that for rack out switchgear, the electrical boundary will be at the busbar shutters.

In the case of **Gas Insulated Switchgear**:

(f) the electrical boundary will be the equivalent of those specified in this Paragraph 2.12.1 save that the electrical boundary will be at:

(i) the first component on the outside of the **Gas Insulated Switchgear Circuit Breaker** gas zone on the **User's** side of that gas zone or, where a circuit disconnector is fitted, the first component on the outside of the **Gas Insulated Switchgear** circuit disconnector gas zone, on the **User's** side of that gas zone; or

(ii) the first gas zone separator on the busbar side of the busbar selection devices, and in such case the busbar selection devices' gas zone
may contain a single section of the busbar as agreed between **The Company** and the **User** and a diagram showing these electrical boundaries is attached
at Schedule 1 to this Section 2.

2.12.2 If a **User** wants to use transformers of specialised design for unusual load characteristics at the electrical boundary, these shall not be owned by the **User** and shall form part of the **National Electricity Transmission System** but the **User** shall pay **The Company** for the proper and reasonable additional cost thereof as identified by **The Company** in the **Offer** covering such transformers. In this Paragraph 2.12.2 "unusual load characteristics" means loads which have characteristics which are significantly different from those of the normal range of domestic, commercial and industrial loads (including loads which vary considerably in duration or magnitude).

2.12.3 For the avoidance of doubt nothing in this Paragraph 2.12 shall
effect any transfer of ownership in any **Plant** or **Apparatus**.

2.14 CONNECTION CHARGES

2.14.1 Introduction

Subject to the provisions of the **CUSC**, and the relevant **Bilateral Connection Agreement,** each **User** shall, as between **The Company** and that **User**, with effect from the relevant date set out in the relevant **Bilateral Connection Agreement**, be liable to pay to **The Company** the **Connection Charges** calculated and applied in accordance with the **Statement of the Connection Charging Methodology** and as set out in the relevant **Bilateral Connection Agreement**. The **User** shall make those payments in accordance with the
provisions of the **CUSC**. **The Company** shall apply and calculate the **Connection Charges** in accordance with the **Statement of the Connection Charging Methodology**.

2.14.3 (b)
The Company shall be entitled to invoice each **User** for **Connection Charges** payable in accordance with the **CUSC** in respect of any **Plant** and **Apparatus** installed as part of the **Transmission Connection Asset Works**
on the basis set out in the **Statement of the Connection Charging Methodology**, until the final cost of carrying out the said **Transmission Connection Asset Works** shall have been determined.

(c) As soon as practicable after the **Completion Date** and in any event within one year (or such later period as **The Company** and the relevant **User** shall agree) thereof. **The Company** shall, as between **The Company** and that **User**, provide to the **User** a written statement specifying the **Connection Charges** calculated in accordance with the **Charging Statements** based on the cost of carrying out the **Transmission Connection Asset Works** (the "**Cost Statement**"). **The Company** shall be entitled to revise Appendix B to the relevant **Bilateral Connection Agreement** accordingly.

2.14.5 Connection Charges – Site Specific Maintenance Charge

(a) **The Company** shall be entitled to invoice each **User** for the indicative **Site Specific Maintenance Charge** in each **Financial Year** as set out in the **Statement of the Connection Charging Methodology**.

2.17 REPLACEMENT OF TRANSMISSION CONNECTION ASSETS

2.17.1 **The Company** will provide information to each **User** on an ongoing basis with regards to its long term intentions and any programme for the replacement of any **Transmission Connection Assets** at a **Connection Site**.

2.17.2 Where in **The Company's** reasonable opinion to enable **The Company** to comply with its statutory and licence duties and\or to enable any **Relevant Transmission Licensee** to comply with its statutory and licence duties it is necessary to replace a **Transmission Connection Asset The Company** shall give written notice of this (a "**Replacement Notice**") such notice to be given (subject to Paragraph 2.17.7) as soon as practicable.

2.17.3 Following the issue of the **Replacement Notice The Company** shall provide an explanation of the economic and engineering reasons to asset replace and the parties shall meet as soon as practicable to consider options, programme and costs associated with the replacement.

2.17.4 **The Company** shall make an offer to the **User(s)** (subject to Paragraph 2.17.7) no earlier than 6 months after the date of the **Replacement Notice** detailing the variations it proposes to make to Appendices A and B of and any other changes required to the **Bilateral Connection Agreement** and if appropriate enclosing a **Construction Agreement** in respect of the replacement of the **Transmission Connection Assets**.

2.17.5 If after a period of 3 months from receipt of the offer or such longer period as the parties might agree the **User(s)** and **The Company** have failed to reach agreement on the offer then either party may make an application to the **Authority** under Standard Condition C9 of the **Transmission Licence** to settle any dispute about the replacement of the **Transmission Connection Assets**.

2.17.6 Subject to Paragraph 2.17.7, **The Company** shall not replace the **Transmission Connection Assets** until the offer has been accepted by the **User(s)** or until the determination of the **Authority** if an application to the **Authority** has been made.

2.17.7 **The Company** shall take all reasonable steps to avoid exercising its rights pursuant to this Paragraph but in the event that **The Company** has reasonable grounds to believe, given its licence and statutory duties or the statutory and licence duties of a **Relevant Transmission Licensee** that a **Transmission Connection Asset** should be replaced prior to or during the process outlined above then **The Company** shall consult with the **User(s)** as far as reasonably practicable and shall be entitled to replace such **Transmission Connection Asset** and shall advise the **User(s)** of this and as soon as practicable make an offer for such replacement which can be accepted or referred in accordance with Paragraph 2.17.5 above.

2.17.8 Subject to Paragraph 2.17.9 **Connection Charges** shall be payable in respect of such replaced **Transmission Connection Assets** in accordance with the **Statement of the Connection Charging Methodology** and **The Company** shall give the **User(s)** not less than 2 months prior written notice of such varied charges and specify the date upon which such charges become effective. **The Company** shall be entitled to invoice the **Connection Charges** based on an estimate of the cost and the provisions of Paragraphs 2.14.3 and 2.14.4 shall apply.

2.17.9 Where **Transmission Connection Assets** have been replaced pursuant to Paragraph 2.17.7 **The Company** shall not be entitled to vary the **Connection Charges** until the offer has been accepted or the matter has been determined by the **Authority** and until such time the **User(s)** shall continue to pay **Connection Charges** as if the **Transmission Connection Assets** had not been replaced. If the matter is determined in **The Company's** favour then **The Company** shall be entitled to issue a revised Appendices A and B and the **User(s)** shall pay to **The Company** the difference between the two amounts plus interest at **Base Rate** on a daily basis from completion of the replacement to the date of payment by the **User(s)**. if the matter is not determined in **The Company's** favour **Connection Charges** shall be payable as directed by the **Authority**.

(CUSC) EXHIBIT B[20]

THE CONNECTION AND USE OF SYSTEM CODE CONNECTION APPLICATION

[20] **http://www.nationalgrid.com/NR/rdonlyres/70F60213-EC10-42C1-BB21-7F604AAB71C6/51399/CUSC_Exhb_B_V113_CAP189_30Jan12.pdf**

Please note that certain terms used in the application form are defined in the Interpretation and Definitions (contained in Section 11 to the **CUSC**) and when this occurs the expressions have capital letters at the beginning of each word and are in bold.

11 **The Company's Offer** will be based upon its standard form terms of **Connection Offer** and the **Charging Statements** issued by **The Company** under Standard Conditions C4 and C6 of the **Transmission Licence**.

Section B

1. Please identify (preferably by reference to an extract from an Ordnance Survey Map for **Onshore** locations, or with the latitude and longitude or some other corresponding equivalent for **Offshore** locations) the intended location (the "**Connection Site**") of the **Plant** and **Apparatus** (the "**User Development**") which it is desired should be connected to the **National Electricity Transmission System** and where the application is in respect of a proposed **New Connection Site** other than at an existing sub-station. Please specify the proposed location and name of the **New Connection Site** (which name should not be the same as or confusingly similar to the name of any other **Connection Site**) together with details of access to the **Connection Site** including from the nearest main road.

2. Please provide a plan or plans of the proposed **Connection Site** indicating (so far as you are now able) the position of all buildings, structures, **Plant** and **Apparatus** and of all services located on the **Connection Site**.

3. Give details of the intended legal estate in the **Connection Site** (to include leasehold and freehold interests and in the case of **Connection Sites** in Scotland legal interests and heritable or leasehold interests including servitudes or other real rights and in the case of **Connection Sites** located **Offshore** leaseholds granted by the Crown Estate) in so far as you are aware.

4. Who occupies the **Connection Site** in so far as you are aware?

5. If you believe that a new sub-station will be needed, please indicate by reference to the plan referred to in Section B question 2 above the **Applicant's** suggested location for it - giving dimensions of the area.

6. If you are prepared to make the land necessary for the said sub-station available to **The Company** or, for **Connection Sites** in Scotland or **Offshore**, make the land or **Offshore Platform** available to the **Relevant Transmission Licensee** ` please set out brief proposals for their interest in it including (if relevant) such interest and the consideration to be paid for it.

7. Is space available on the **Connection Site** for working storage and accommodation areas for **The Company** contractors or, for **Connection Sites** in Scotland, the contractors of the **Relevant Transmission Licensee**? If so, please indicate by reference to the plan referred to in Section B question 2 above the location of such areas, giving the approximate dimensions of the same.

8. For **Connection Sites** located **Onshore**, please provide details (including copies of any surveys or reports) of the physical nature of land in which you have a legal estate or legal interest at the proposed **Connection Site** including the nature of the ground and the sub-soil.

9. Please give details and provide copies of all existing relevant planning and other consents (statutory or otherwise) relating to the **Connection Site** and the **User Development** and/or details of any pending applications for the same.

10. Is access to or use of the **Connection Site** for the purposes of installing, maintaining and operating **Plant** and **Apparatus** subject to any existing restrictions? If so, please give details.

11. If you are aware of them, identify by reference to a plan (if possible) the owners and (if different) occupiers of the land adjoining the **Connection Site**. To the extent that you have information, give brief details of the owner's and occupier's estates and/or interests in such land.

APPLICATION FOR A NEW CONNECTION

8. Do you wish to suggest an ownership boundary different from that set out in **CUSC** Paragraph 2.12?

9. Please confirm which ownership boundary at **CUSC** Paragraph 2.12.1 (f) you would want in the event that the **Transmission** substation at which the **Applicant** is to be connected is to be of a **Gas Insulated Switchgear** design:

(a) **CUSC** Paragraph 2.12.1 (f) (i) [ ]

(b) **CUSC** Paragraph 2.12.1 (f) (ii) [ ]

Please note that in the case where the ownership boundary is in accordance with **CUSC** Paragraph 2.12.1 (f) (i) restrictions on availability as described within **CUSC** Schedule 2 Exhibit 1 will apply in the event of a **GIS Asset Outage**.

10. Are you considering building any assets that would be identified as **Transmission Connection Assets**? If you indicate yes **The Company** will contact you to discuss further details.

CONNECTION APPLICATION

1. We hereby apply to connect our **Plant** and **Apparatus** to the **National Electricity Transmission System** at a **New Connection Site**. We agree to pay **The Company's** Engineering Charges on the terms specified in the **Notes** to the **Connection Application**.

CUSC Workgroup Consultation Response Proforma

CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users

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

Please send your responses by **23 January** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Tushar Singh at tushar.singh@nationalgrid.com.

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

Respondent:	*Please insert your name and contact details (phone number or email address)*
Company Name:	VPI Immingham
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We understand that the proposal is confined to ensuring that any limit set out in Regulation 838/2010 is not breached and we support that the transmission charges methodology should recognise the need to remain within the range determined in EC Regulation 838/2010, whether it remains the same or changes after the European Commission's forthcoming review However, we consider there should be fundamental review of the split of TNUoS charges between generation and supply with a view to charging either all or a much higher proportion of TNUoS to demand. The requirements of the Regulation should form one element of this, and will set an important boundary. This proposal, by addressing only the issues arising from the Regulation and not the issue of the split itself has as a consequence needed to address a range of subsidiary issues such as what charges should be included, and what should happen to the split should the Regulation be breached in one year and then not the next. These issues could largely be avoided. In our view moving the TNUoS charges to be wholly or very largely paid by the demand side would bring the UK closer into line with the rest of Europe and promote competition within it by creating a more level playing field. It is striking that of the 32 countries that ENTSO-E considered in its overview report of transmission tariffs in Europe

	published in July 2013 (available here) that only Norway allocated a higher proportion of network charges to generation. We also note that 21 other EU Member States are required to keep their transmission charges for generation to range of zero to €0.5/MWh, compared to zero to €2.5/MWh for the UK. The increasing levels and volatility of generation charges, due in part to the RIIO-T1 settlement and the increasing residual charge should also be addressed in a review. The issue of the G/D split has consistently been top of the list of issues that members of the Transmission Charging Methodology Forum would like to see addressed. The requirements of the Regulation should be considered as part of this and not separately in advance. The split should be based on one rational justification at all times, and not set at one level ie 27/73 on one basis, to then be nudged away from this on the basis of another basis eg the EC Regulation. We do not believe that it is appropriate to tamper with the interpretation of what local assets can be considered as "connection" in the context of the EC Regulation in order to avoid or delay the risk of non-compliance with it. The modification should not strive to effectively manipulate the definition of the charges in order to remain within the current requirements. We note the opinion obtained from National Grid's legal team that the clearest interpretation seems to be to include what in the GB regime is set as local TNUoS charges and that excluding these local charges from the calculation of annual average transmission charges leaves scope for challenge to the GB charging regime. On the basis of these two points we therefore agree with those workgroup members that believe that all local charges should be included within the total of annual average transmission charges paid by generators in GB when considering the €2.5/MWh upper limit.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We consider the proposal would better facilitate objective c) in respect of properly taking account of developments in transmission licensees' transmission businesses. This is because Regulation 838/2010 imposes legally binding requirements on transmission licensees which National Grid must take into account and comply with.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.**	Yes, the working group current assumption is that the proposal should come into effect prior to the start of the next charging year after the Authority decision, provided this is made by 30 November. We believe as much notice as possible should be provided of any change. We note the misalignment between the TNUoS charging year and the potentially effective date of 1 January 2015 if the Regulation is revised. We agree with workgroup members that it is not a preferable option for there to be a mid-year TNUoS tariff change to ensure GB remains compliant with a revised limit and note the two options proposed to address the issue over the charging year.
2	**Do you have any other comments?**	No
3	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP224

Q	Question	Response
4	**Do you believe that the Workgroup has considered all potential interpretations of “charges paid by producers for physical assets required for connection to the system or the upgrade of the connection” to be excluded from the annual average transmission charge referred to under EC Regulation 838/2010?**	We have no further interpretations to add.

Q	Question	Response
5	**Do you believe that any Local Generation TNUoS Charges (or a subset thereof listed in Table 1 or otherwise) should be excluded from the annual average transmission charge as part of defining a cap on the proportion of TNUoS charges paid by generation under the proposed solution?**	We do not believe that any of the local generation charges should be excluded.
6	**Do you believe that based upon the summary legal opinion from National Grid it would be sensible to include assets subject to local TNUoS charges within the calculation of the annual average transmission charges for GB for the reason set out?**	Yes, we agree with this reasoning.
7	**Do you believe that the application of an additional bandwidth to manage the risk of potential breaches of the limit set out in EC Regulation 838/2010 is appropriate?**	We agree that it would be sensible to have a margin on the cap to avoid a breach of the Regulation limits. The use of a bandwith seems appropriate within the terms of the proposal.
8	**Do you believe that the G/D split should revert back to 27:73 in charging years following the application of the proposed cap (assuming no breach of the EC Regulation)?**	We have explained above that we believe there should be a review of the G/D split. The idea that the split would return to 27:73 having been pushed away from this by the Regulation illustrates the illogical approach.

CUSC WORKGROUP CONSULTATION ALTERNATIVE REQUEST FORM

Please send your completed form along with your completed Workgroup Consultation Response to CMP224 by RWE npower

Please note that any responses received after the deadline may not receive due consideration by the Workgroup.

Respondent Name and contact details	*George Douthwaite*
CMP224 - Cap on the total TNUoS target revenue to be recovered from Generation Users	
Capacity in which the WG Consultation Alternative Request is being raised : (i.e. CUSC Party, BSC Party or “National Consumer Council ”)	CUSC Party

Description of the Proposal for the Workgroup to consider

We consider that the current modification does not allow sufficient time for the market to adjust to the new cost allocation between Generation and Supply that this modification would create. Therefore we believe that a timeframe for implementation within the modification (as for CMP201) would allow greater certainty for the market.

We propose that CMP224 is implemented with at least 12 months notice. Ie if Authority approval is granted by the end of March implementation will be from April in the following year. If Authority approval occurs after the end of March implementation will be from the April two years after.

As an example of this if the Authority was to direct implementation by the 31st March 2014 then implementation could occur from April 2015. If a decision was received after the 31st March 2014 but prior to 31st March 2015 then implementation would be from April 2016.

As stated in our main response, we believe this alternative should be taken forward in conjunction with option iv of table 1 for removal of Local charges for radial spur connections from the calculation of average transmission TNUoS. This is to provide additional market stability; the sharing factor would still be a valuable tool in the longer term to avoid tolerance breaches (or brought into action earlier should the European Commission overturn this interpretation of the rules).

Description of the difference(s) between your proposal compared to Original / Workgroup Alternative(s)

We do not believe it to be acceptable that a short notice change is inflicted upon market participants due to anticipatable regulations. The specific EU directive that this modification looks to address commenced in 2010. During that period we have had a series of price control negotiations relating to the RIIO-T1 period during which this issue could have been raised and stakeholder opinion facilitated.

We are sympathetic in some form to the issues that NGET will face which is why we have proposed a 12 month period as opposed to the 2 year period that CMP201 advocated. However, we believe a 2 year period would be far more beneficial to the market and customers.

Justification for the proposal (*<u>including why the Original proposal / Workgroup Alternative(s) does not address the defect</u>*) *This proposal seeks to complement the work already done by giving the market a clear and transparent implementation timetable as a result of this change. This will improve engagement and market transparency for all parties and for customers.* *Customers particularly those with pass-through supply contracts are also in the process of establishing budgets and managing costs for the next 12-18 months. Therefore any increases to core elements of their cost base (such as energy) will be detrimental to heir businesss. Customers already face large uncertainty in tariffs due to other elements of government policy and regulation increasing this through this change will not be a positive contribution to the UK economy.*
Impact on the CUSC *(this should be given where possible)*:
Impact on Core Industry Documentation *(this should be given where possible)*:
Impact on Computer Systems and Processes used by CUSC Parties *(this should be given where possible):*
Justification for the proposal with Reference to Applicable CUSC Objectives* *(mandatory by proposer)*: **(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;** We believe that this proposal better meets this objective than the original as it allows the market to respond to the redistribution of costs therefore improving transparency and better facilitates competiton. **(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);** This proposal meets this objective equally as well as the original. **(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.** This proposal meets this objective equally as well as the original.

Attachments (Yes/No): **If Yes, Title and No. of pages of each Attachment:**	No

Notes:

1. Applicable CUSC Objectives* - These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1. Reference should be made to this section when considering a proposed Modification.

Annex 6 – Draft legal text

<u>Legal Text for CMP224 Original</u>

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.1 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.2 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.3 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)**".

14.14.4 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

14.14.5 In April 2004 The Company introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales charging methodology. The DCLF model has been extended to incorporate Scottish network data with existing England and Wales network data to form the GB network in the model. In April 2005, the GB charging methodology implemented the following proposals:

i.) The application of multi-voltage circuit expansion factors with a forward-looking Expansion Constant that does not include substation costs in its derivation.

ii.) The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.

iii.) The application of a de-minimus level demand charge of £0/kW for Half Hourly and £0/kWh for Non Half Hourly metered demand to avoid the introduction of negative demand tariffs.

iv.) The application of 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.

v.) The application of a Transmission Network Use of System Revenue split between generation and demand, where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

Deleted: of 27% and 73% respectively

$$x_n = \frac{(Cap_{EC} * (1 - y)) * GO}{MAR * ER}$$

Field Code Changed

Where;

Cap_{EC}	=	Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation
y	=	Error margin built in to adjust Cap_{EC} to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n
GO	=	Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n
MAR	=	Forecast TO Maximum Allowed Revenue (£) for charging year n
ER	=	OBR Spring Forecast €/£ Exchange Rate in charging year n-1

vi.) The number of generation zones using the criteria outlined in paragraph 14.15.35 has been determined as 21.

vii.) The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

14.15.73 The next stage is to correct the Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained. In order to achieve the 'correct' generation/demand revenue split, a single additive constant C is calculated which is then added to the total zonal marginal km, both for generation and demand as below:

Deleted: This has been determined to be 27:73 by the Authority for generation and demand respectively.

Deleted:

$$\sum_{Gi=1}^{21} \left[(ZMkm_{Gi} + C) \times EC \times LSF \times G_{Gi} \right] = CTRR_G$$

$$\sum_{Di=1}^{14} \left[(ZMkm_{Di} - C) \times EC \times LSF \times D_{Di} \right] = CTRR_D$$

Where C is set such that

$$CTRR_D = p(CTRR_G + CTRR_D)$$

Where

CTRR	=	"Generation / Demand split" corrected transport revenue recovery
p	=	Proportion of revenue to be recovered from demand
C	=	"Generation /Demand split" Correction constant (in km)

14.22 Example: Calculation of Zonal Generation Tariff

Let us consider all nodes in generation zone 4: Western Highland.

The table below shows a sample output of the transport model comprising the node, the wider nodal marginal km (observed on non-local assets) of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand.

Genzone	Node	Wider Nodal Marginal km	Scaled Generation
4	LAGG1Q	1113.41	0.00
4	CEAN1Q	1133.18	54.41
4	FASN10	1143.82	38.50
4	FAUG10	1100.10	0.00
4	FWIL1Q	1009.79	0.00
4	FWIL1R	1009.79	0.00
4	GLEN1Q	1123.82	43.52
4	INGA1Q	1087.40	16.74
4	MILL1Q	1101.55	0.00
4	MILL1S	1106.76	0.00
4	QUOI10	1123.82	15.07
4	QUOI1Q	**1120.49**	0.00
4	LOCL1Q	**1082.41**	0.00
4	LOCL1R	**1082.41**	0.00
		Totals	168.24

In order to calculate the generation tariff we would carry out the following steps.

(i) calculate the generation weighted wider nodal shadow costs.

For zone 4 this would be as follows:

Genzone	Node	Wider Nodal Marginal km	Scaled Generation (MW)	Gen Weighted Wider Nodal Marginal km
4	CEAN1Q	1133.18	54.41	366.48

4	FASN10	1143.82	38.50	261.75
4	GLEN1Q	1123.82	43.52	290.71
4	INGA1Q	1087.40	16.74	108.20
4	QUOI10	1123.82	15.07	100.67
		Totals	168.24	

i.e. 1087.40 x 16.74
168.24

(ii) sum the generation weighted wider nodal shadow cost to give a zonal figure. For zone 4 this would be:

(366.48+ 261.75 +290.71 + 108.20 + 100.67) km = **1127.81km**

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approx) split (if applicable, or such other figure(s) as calculated in accordance with the formula in 14.14.5 v.)) of revenue recovery between generation and demand is retained.

For zone 4 this would be say:

1127.81km + (-239.60 km) = **888.21 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

14.23 Example: Calculation of Zonal Demand Tariff

In order to calculate the demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For zone 14 this would be as follows:

Demand zone	Node	Nodal Marginal km	Demand (MW)	Demand Weighted Nodal Marginal km
14	ABHA4A	-381.25	148.5	-18.39
14	ABHA4B	-381.72	148.5	-18.42
14	ALVE4A	-328.31	113	-12.05
14	ALVE4B	-328.31	113	-12.05
14	AXMI40_SWEB	-337.53	117	-12.83
14	BRWA2A	-281.64	92.5	-8.46

14	BRWA2B	-281.72	92.5	-8.47
14	EXET40	-320.12	357	-37.13
14	HINP20	-247.67	4	-0.32
14	INDQ40	-401.28	450	-58.67
14	IROA20_SWEB	-194.88	594	-37.61
14	LAND40	-438.65	297	-42.33
14	MELK40_SWEB	-162.96	102	-5.40
14	SEAB40	-63.21	352	-7.23
14	TAUN4B	-273.79	97	-8.63
		Totals	3078	287.99

(ii) sum the demand weighted nodal shadow cost to give a zonal figure. For zone 14 this is shown in the above table and is 287.99km.

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approximate) split (if applicable, or such other figure(s) as calculated in accordance with the formula in 14.14.5 v.)) of revenue recovery between generation and demand is retained.

For zone 14 this would be say:

287.99km - (-239.60km) = **527.59 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

14.28 Stability & Predictability of TNUoS tariffs

Predictability of tariffs

The Company revises TNUoS tariffs each year to ensure that these remain cost-reflective and take into account changes to allowable income under the price control and RPI. There are a number of provisions within The Company's Transmission Licence and the CUSC designed to promote the predictability of annually varying charges. Specifically, The Company is required to give the Authority 150 days notice of its intention to change use of system charges together with a reasonable assessment of the proposals on those charges; and to give Users 2 months written notice of any revised charges. The Company typically provides an additional months notice of revised charges through the publication of "indicative" tariffs. Shorter notice periods are permitted by the framework but only following consent from the Authority.

These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority's veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

To supplement this, The Company also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years.[1] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- an explanation of the events that have caused tariffs to change;
- sensitivity analysis to indicate how generation and demand tariffs would change as a result of changes in generation and demand at certain points on the network that are not included within the SYS;
- an assessment of the compliance with the zoning criteria throughout the five year period to indicate how generation zones might need to change in the future, with a view to minimising such changes and giving as much notice of the need, or potential need, to change generation zones; and
- a complete dataset for the DCLF Transport Model developed for each future year, to allow Users to undertake their own sensitivity analysis for specific scenarios that they may wish to model.

The first year of tariffs forecasted in the annual information paper are updated twice throughout the proceeding financial year as the various Transport and Tariff model inputs are received or amended. These updates are in addition to the Authority 150 days notice and publication of "indicative" tariffs.

The parameters used in the calculation of generation cap (in paragraph 14.15.5 v.)) will be published along with the forecast and confirmed values in the Tariff Information Paper which is produced in compliance with Condition 5 (of the NGC's proposed GB electricity transmission use of system charging methodology - the Authority's decisions document March 2005 80/5).

In addition, The Company will, when revising generation charging zones prior to a new price control period, undertake a zoning consultation that uses data from the latest information paper. The purpose of this consultation will be to ensure tariff zones are robust to contracted changes in generation and supply, which could be expected to reduce the need for re-zoning exercises within a price control period.

[1] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

Legal Text for CMP224 WACM1

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.1 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.2 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.3 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.4 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

14.14.5 In April 2004 The Company introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales charging methodology. The DCLF model has been extended to incorporate Scottish network data with existing England and Wales network data to form the GB network in the model. In April 2005, the GB charging methodology implemented the following proposals:

i.) The application of multi-voltage circuit expansion factors with a forward-looking Expansion Constant that does not include substation costs in its derivation.

ii.) The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.

iii.) The application of a de-minimus level demand charge of £0/kW for Half Hourly and £0/kWh for Non Half Hourly metered demand to avoid the introduction of negative demand tariffs.

iv.) The application of 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.

v.) The application of a Transmission Network Use of System Revenue split between generation and demand, where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

Deleted: of 27% and 73% respectively

$$x_n = \frac{(Cap_{EC} * (1 - y)) * GO}{MAR * ER}$$

Field Code Changed

Where;

Cap_{EC}	=	Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation
y	=	Error margin built in to adjust Cap_{EC} to account for difference in two year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n
GO	=	Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n
MAR	=	Forecast TO Maximum Allowed Revenue (£) for charging year n
ER	=	OBR Spring Forecast €/£ Exchange Rate in charging year n-2

x_n will be set and published not less than 12 months prior to the start of charging year n (except if the implementation date of CUSC Modification CMP224 is less than 12 months from when it is approved, in which case x_n will be set and published as soon as reasonably practicable after the approval).

vi.) The number of generation zones using the criteria outlined in paragraph 14.15.35 has been determined as 21.

vii.) The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

14.15.73 The next stage is to correct the Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained. In order to achieve the 'correct' generation/demand revenue split, a single

Deleted: This has been determined to be 27:73 by the Authority for generation and demand respectively.

Deleted:

additive constant C is calculated which is then added to the total zonal marginal km, both for generation and demand as below:

$$\sum_{Gi=1}^{21}\left[\left(ZMkm_{Gi}+C\right)\times EC\times LSF\times G_{Gi}\right]=CTRR_G$$

$$\sum_{Di=1}^{14}\left[\left(ZMkm_{Di}-C\right)\times EC\times LSF\times D_{Di}\right]=CTRR_D$$

Where C is set such that

$$CTRR_D = p\left(CTRR_G + CTRR_D\right)$$

Where

CTRR	=	"Generation / Demand split" corrected transport revenue recovery
p	=	Proportion of revenue to be recovered from demand
C	=	"Generation /Demand split" Correction constant (in km)

14.22 Example: Calculation of Zonal Generation Tariff

Let us consider all nodes in generation zone 4: Western Highland.

The table below shows a sample output of the transport model comprising the node, the wider nodal marginal km (observed on non-local assets) of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand.

Genzone	Node	Wider Nodal Marginal km	Scaled Generation
4	LAGG1Q	1113.41	0.00
4	CEAN1Q	1133.18	54.41
4	FASN10	1143.82	38.50
4	FAUG10	1100.10	0.00
4	FWIL1Q	1009.79	0.00
4	FWIL1R	1009.79	0.00
4	GLEN1Q	1123.82	43.52
4	INGA1Q	1087.40	16.74
4	MILL1Q	1101.55	0.00
4	MILL1S	1106.76	0.00
4	QUOI10	1123.82	15.07
4	QUOI1Q	**1120.49**	0.00
4	LOCL1Q	**1082.41**	0.00
4	LOCL1R	**1082.41**	0.00
		Totals	168.24

In order to calculate the generation tariff we would carry out the following steps.

(i) calculate the generation weighted wider nodal shadow costs.

For zone 4 this would be as follows:

Genzone	Node	Wider Nodal Marginal km	Scaled Generation (MW)	Gen Weighted Wider Nodal Marginal km
4	CEAN1Q	1133.18	54.41	366.48
4	FASN10	1143.82	38.50	261.75
4	GLEN1Q	1123.82	43.52	290.71
4	INGA1Q	1087.40	16.74	108.20
4	QUOI10	1123.82	15.07	100.67
		Totals	168.24	

i.e. $\frac{1087.40 \times 16.74}{168.24}$

(ii) sum the generation weighted wider nodal shadow cost to give a zonal figure. For zone 4 this would be:

(366.48+ 261.75 +290.71 + 108.20 + 100.67) km = **1127.81km**

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approx) split (if applicable, or such other figure(s) as calculated in accordance with the formula in 14.14.5 v.)) of revenue recovery between generation and demand is retained.

For zone 4 this would be say:

1127.81km + (-239.60 km) = **888.21 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

14.23 Example: Calculation of Zonal Demand Tariff

In order to calculate the demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For zone 14 this would be as follows:

Demand zone	Node	Nodal Marginal km	Demand (MW)	Demand Weighted Nodal Marginal km

14	ABHA4A	-381.25	148.5	-18.39
14	ABHA4B	-381.72	148.5	-18.42
14	ALVE4A	-328.31	113	-12.05
14	ALVE4B	-328.31	113	-12.05
14	AXMI40_SWEB	-337.53	117	-12.83
14	BRWA2A	-281.64	92.5	-8.46
14	BRWA2B	-281.72	92.5	-8.47
14	EXET40	-320.12	357	-37.13
14	HINP20	-247.67	4	-0.32
14	INDQ40	-401.28	450	-58.67
14	IROA20_SWEB	-194.88	594	-37.61
14	LAND40	-438.65	297	-42.33
14	MELK40_SWEB	-162.96	102	-5.40
14	SEAB40	-63.21	352	-7.23
14	TAUN4B	-273.79	97	-8.63
		Totals	3078	287.99

(ii) sum the demand weighted nodal shadow cost to give a zonal figure. For zone 14 this is shown in the above table and is 287.99km.

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approximate) split (if applicable, or such other figure(s) as calculated in accordance with the formula in 14.14.5 v.)) of revenue recovery between generation and demand is retained.

For zone 14 this would be say:

287.99km - (-239.60km) = **527.59 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

14.28 Stability & Predictability of TNUoS tariffs

Predictability of tariffs

The Company revises TNUoS tariffs each year to ensure that these remain cost-reflective and take into account changes to allowable income under the price control and RPI. There are a number of provisions within The Company's Transmission Licence and the CUSC designed to promote the predictability of annually varying charges. Specifically, The Company is required to give the Authority 150 days notice of its intention to change use of system charges together with a reasonable assessment of the proposals on those charges; and to give Users 2 months written notice of any revised charges. The Company typically provides an additional months notice of revised charges through the publication of "indicative" tariffs. Shorter notice periods are permitted by the framework but only following consent from the Authority.

These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority's veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

To supplement this, The Company also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years.[1] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- an explanation of the events that have caused tariffs to change;
- sensitivity analysis to indicate how generation and demand tariffs would change as a result of changes in generation and demand at certain points on the network that are not included within the SYS;
- an assessment of the compliance with the zoning criteria throughout the five year period to indicate how generation zones might need to change in the future, with a view to minimising such changes and giving as much notice of the need, or potential need, to change generation zones; and
- a complete dataset for the DCLF Transport Model developed for each future year, to allow Users to undertake their own sensitivity analysis for specific scenarios that they may wish to model.

The first year of tariffs forecasted in the annual information paper are updated twice throughout the proceeding financial year as the various Transport and Tariff model inputs are received or amended. These updates are in addition to the Authority 150 days notice and publication of "indicative" tariffs.

The parameters used in the calculation of generation cap (in paragraph 14.15.5 v.)) will be published along with the forecast and confirmed values in the Tariff Information Paper which is produced in compliance with Condition 5 (of the NGC's proposed GB electricity transmission use of system charging methodology - the Authority's decisions document March 2005 80/5).

In addition, The Company will, when revising generation charging zones prior to a new price control period, undertake a zoning consultation that uses data from the latest information paper. The purpose of this consultation will be to ensure tariff zones are robust to contracted changes in generation and supply, which could be expected to reduce the need for re-zoning exercises within a price control period.

[1] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

Legal Text for CMP224 WACM2

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.1 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.2 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.3 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.4 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

14.14.5 In April 2004 The Company introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales charging methodology. The DCLF model has been extended to incorporate Scottish network data with existing England and Wales network data to form the GB network in the model. In April 2005, the GB charging methodology implemented the following proposals:

i.) The application of multi-voltage circuit expansion factors with a forward-looking Expansion Constant that does not include substation costs in its derivation.

ii.) The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.

iii.) The application of a de-minimus level demand charge of £0/kW for Half Hourly and £0/kWh for Non Half Hourly metered demand to avoid the introduction of negative demand tariffs.

iv.) The application of 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.

v.) The application of a Transmission Network Use of System Revenue split between generation and demand, where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

Deleted: of 27% and 73% respectively

$$x_n = \frac{[(Cap_{EC} * (1 - y)) * GO] + \mathrm{Re}\, v_{Spurs} * ER}{MAR * ER}$$

Field Code Changed

Where;

Cap_{EC}	=	Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation
y	=	Error margin built in to adjust Cap_{EC} to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n
GO	=	Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n
Rev_{Spurs}	=	Forecast Revenue from generation only spur connections in charging year n
MAR	=	Forecast TO Maximum Allowed Revenue (£) for charging year n
ER	=	OBR Spring Forecast €/£ Exchange Rate in charging year n-1

vi.) The number of generation zones using the criteria outlined in paragraph 14.15.35 has been determined as 21.

vii.) The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

14.15.73 The next stage is to correct the Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained. In order to achieve the 'correct' generation/demand revenue split, a single additive constant C is calculated which is then added to the total zonal marginal km, both for generation and demand as below:

Deleted: This has been determined to be 27:73 by the Authority for generation and demand respectively.

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$$\sum_{Gi=1}^{21}\left[\left(ZMkm_{Gi}+C\right)\times EC\times LSF\times G_{Gi}\right]=CTRR_G$$

$$\sum_{Di=1}^{14}\left[\left(ZMkm_{Di}-C\right)\times EC\times LSF\times D_{Di}\right]=CTRR_D$$

Where C is set such that

$$CTRR_D = p\left(CTRR_G + CTRR_D\right)$$

Where		
CTRR	=	"Generation / Demand split" corrected transport revenue recovery
p	=	Proportion of revenue to be recovered from demand
C	=	"Generation /Demand split" Correction constant (in km)

14.22 Example: Calculation of Zonal Generation Tariff

Let us consider all nodes in generation zone 4: Western Highland.

The table below shows a sample output of the transport model comprising the node, the wider nodal marginal km (observed on non-local assets) of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand.

Genzone	Node	Wider Nodal Marginal km	Scaled Generation
4	LAGG1Q	1113.41	0.00
4	CEAN1Q	1133.18	54.41
4	FASN10	1143.82	38.50
4	FAUG10	1100.10	0.00
4	FWIL1Q	1009.79	0.00
4	FWIL1R	1009.79	0.00
4	GLEN1Q	1123.82	43.52
4	INGA1Q	1087.40	16.74
4	MILL1Q	1101.55	0.00
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4	QUOI10	1123.82	15.07
4	QUOI1Q	**1120.49**	0.00
4	LOCL1Q	**1082.41**	0.00
4	LOCL1R	**1082.41**	0.00
		Totals	168.24

In order to calculate the generation tariff we would carry out the following steps.

(i) calculate the generation weighted wider nodal shadow costs.

For zone 4 this would be as follows:

Genzone	Node	Wider Nodal Marginal km	Scaled Generation (MW)	Gen Weighted Wider Nodal Marginal km
4	CEAN1Q	1133.18	54.41	366.48
4	FASN10	1143.82	38.50	261.75
4	GLEN1Q	1123.82	43.52	290.71
4	INGA1Q	1087.40	16.74	108.20
4	QUOI10	1123.82	15.07	100.67
		Totals	168.24	

i.e. $\frac{1087.40 \times 16.74}{168.24}$

(ii) sum the generation weighted wider nodal shadow cost to give a zonal figure. For zone 4 this would be:

(366.48+ 261.75 +290.71 + 108.20 + 100.67) km = **1127.81km**

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approx) split (if applicable, or such other figure(s) as calculated in accordance with the formula in 14.14.5 v.)) of revenue recovery between generation and demand is retained.

For zone 4 this would be say:

1127.81km + (-239.60 km) = **888.21 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

14.23 Example: Calculation of Zonal Demand Tariff

In order to calculate the demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For zone 14 this would be as follows:

Demand zone	Node	Nodal Marginal km	Demand (MW)	Demand Weighted Nodal Marginal km
14	ABHA4A	-381.25	148.5	-18.39
14	ABHA4B	-381.72	148.5	-18.42
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14	HINP20	-247.67	4	-0.32
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14	IROA20_SWEB	-194.88	594	-37.61
14	LAND40	-438.65	297	-42.33
14	MELK40_SWEB	-162.96	102	-5.40
14	SEAB40	-63.21	352	-7.23
14	TAUN4B	-273.79	97	-8.63
		Totals	3078	287.99

(ii) sum the demand weighted nodal shadow cost to give a zonal figure. For zone 14 this is shown in the above table and is 287.99km.

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approximate) split (if applicable, or such other figure(s) as calculated in accordance with the formula in 14.14.5 v.)) of revenue recovery between generation and demand is retained.

For zone 14 this would be say:

287.99km - (-239.60km) = **527.59 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

14.28 Stability & Predictability of TNUoS tariffs

Predictability of tariffs

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These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority's veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

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- an explanation of the events that have caused tariffs to change;
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The first year of tariffs forecasted in the annual information paper are updated twice throughout the proceeding financial year as the various Transport and Tariff model inputs are received or amended. These updates are in addition to the Authority 150 days notice and publication of "indicative" tariffs.

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[1] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

Legal Text for CMP224 WACM3

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.1 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.2 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.3 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.4 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

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ii.) The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.

iii.) The application of a de-minimus level demand charge of £0/kW for Half Hourly and £0/kWh for Non Half Hourly metered demand to avoid the introduction of negative demand tariffs.

iv.) The application of 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.

v.) The application of a Transmission Network Use of System Revenue split between generation and demand, where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

Deleted: of 27% and 73% respectively

$$x_n = \frac{[(Cap_{EC} * (1-y)) * GO] + Rev_{Spurs} * ER}{MAR * ER}$$

Where;

Cap_{EC}	=	Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation
y	=	Error margin built in to adjust Cap_{EC} to account for difference in two year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n
GO	=	Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n
Rev_{Spurs}	=	Forecast Revenue from generation only spur connections in charging year n
MAR	=	Forecast TO Maximum Allowed Revenue (£) for charging year n
ER	=	OBR Spring Forecast €/£ Exchange Rate in charging year n-2

x_n will be set and published not less than 12 months prior to the start of charging year n (except if the implementation date of CUSC Modification CMP224 is less than 12 months from when it is approved, in which case x_n will be set and published as soon as reasonably practicable after the approval)

.

vi.) The number of generation zones using the criteria outlined in paragraph 14.15.35 has been determined as 21.

vii.) The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

14.15.73 The next stage is to correct the Initial Transport Revenue Recovery figures above such that the 'correct' split of revenue between generation and demand is obtained. In order to achieve the 'correct' generation/demand revenue split, a single additive constant C is calculated which is then added to the total zonal marginal km, both for generation and demand as below:

Deleted: This has been determined to be 27:73 by the Authority for generation and demand respectively

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$$\sum_{Gi=1}^{21}\left[(ZMkm_{Gi}+C)\times EC\times LSF\times G_{Gi}\right]=CTRR_G$$

$$\sum_{Di=1}^{14}\left[(ZMkm_{Di}-C)\times EC\times LSF\times D_{Di}\right]=CTRR_D$$

Where C is set such that

$$CTRR_D = p(CTRR_G + CTRR_D)$$

Where

CTRR	=	"Generation / Demand split" corrected transport revenue recovery
p	=	Proportion of revenue to be recovered from demand
C	=	"Generation /Demand split" Correction constant (in km)

14.22 Example: Calculation of Zonal Generation Tariff

Let us consider all nodes in generation zone 4: Western Highland.

The table below shows a sample output of the transport model comprising the node, the wider nodal marginal km (observed on non-local assets) of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand.

Genzone	Node	Wider Nodal Marginal km	Scaled Generation
4	LAGG1Q	1113.41	0.00
4	CEAN1Q	1133.18	54.41
4	FASN10	1143.82	38.50
4	FAUG10	1100.10	0.00
4	FWIL1Q	1009.79	0.00
4	FWIL1R	1009.79	0.00
4	GLEN1Q	1123.82	43.52
4	INGA1Q	1087.40	16.74
4	MILL1Q	1101.55	0.00
4	MILL1S	1106.76	0.00
4	QUOI10	1123.82	15.07
4	QUOI1Q	**1120.49**	0.00
4	LOCL1Q	**1082.41**	0.00
4	LOCL1R	**1082.41**	0.00
		Totals	168.24

In order to calculate the generation tariff we would carry out the following steps.

(i) calculate the generation weighted wider nodal shadow costs.

For zone 4 this would be as follows:

Genzone	Node	Wider Nodal Marginal km	Scaled Generation (MW)	Gen Weighted Wider Nodal Marginal km
4	CEAN1Q	1133.18	54.41	366.48
4	FASN10	1143.82	38.50	261.75
4	GLEN1Q	1123.82	43.52	290.71
4	INGA1Q	1087.40	16.74	108.20
4	QUOI10	1123.82	15.07	100.67
		Totals	168.24	

i.e. $\frac{1087.40 \times 16.74}{168.24}$

(ii) sum the generation weighted wider nodal shadow cost to give a zonal figure. For zone 4 this would be:

(366.48+ 261.75 +290.71 + 108.20 + 100.67) km = **1127.81km**

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approx) split (if applicable, or such other figure(s) as calculated in accordance with the formula in 14.14.5 v.)) of revenue recovery between generation and demand is retained.

For zone 4 this would be say:

1127.81km + (-239.60 km) = **888.21 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

14.23 Example: Calculation of Zonal Demand Tariff

In order to calculate the demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For zone 14 this would be as follows:

Demand zone	Node	Nodal Marginal km	Demand (MW)	Demand Weighted Nodal Marginal km
14	ABHA4A	-381.25	148.5	-18.39
14	ABHA4B	-381.72	148.5	-18.42

14	ALVE4A	-328.31	113	-12.05
14	ALVE4B	-328.31	113	-12.05
14	AXMI40_SWEB	-337.53	117	-12.83
14	BRWA2A	-281.64	92.5	-8.46
14	BRWA2B	-281.72	92.5	-8.47
14	EXET40	-320.12	357	-37.13
14	HINP20	-247.67	4	-0.32
14	INDQ40	-401.28	450	-58.67
14	IROA20_SWEB	-194.88	594	-37.61
14	LAND40	-438.65	297	-42.33
14	MELK40_SWEB	-162.96	102	-5.40
14	SEAB40	-63.21	352	-7.23
14	TAUN4B	-273.79	97	-8.63
		Totals	3078	287.99

(ii) sum the demand weighted nodal shadow cost to give a zonal figure. For zone 14 this is shown in the above table and is 287.99km.

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approximate) split (if applicable, or such other figure(s) as calculated in accordance with the formula in 14.14.5 v.)) of revenue recovery between generation and demand is retained.

For zone 14 this would be say:

287.99km - (-239.60km) = **<u>527.59 km</u>**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

14.28 Stability & Predictability of TNUoS tariffs

Predictability of tariffs

The Company revises TNUoS tariffs each year to ensure that these remain cost-reflective and take into account changes to allowable income under the price control and RPI. There are a number of provisions within The Company's Transmission Licence and the CUSC designed to promote the predictability of annually varying charges. Specifically, The Company is required to give the Authority 150 days notice of its intention to change use of system charges together with a reasonable assessment of the proposals on those charges; and to give Users 2 months written notice of any revised charges. The Company typically provides an additional months notice of revised charges through the publication of "indicative" tariffs. Shorter notice periods are permitted by the framework but only following consent from the Authority.

These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority's veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

To supplement this, The Company also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years.[1] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- an explanation of the events that have caused tariffs to change;
- sensitivity analysis to indicate how generation and demand tariffs would change as a result of changes in generation and demand at certain points on the network that are not included within the SYS;
- an assessment of the compliance with the zoning criteria throughout the five year period to indicate how generation zones might need to change in the future, with a view to minimising such changes and giving as much notice of the need, or potential need, to change generation zones; and
- a complete dataset for the DCLF Transport Model developed for each future year, to allow Users to undertake their own sensitivity analysis for specific scenarios that they may wish to model.

The first year of tariffs forecasted in the annual information paper are updated twice throughout the proceeding financial year as the various Transport and Tariff model inputs are received or amended. These updates are in addition to the Authority 150 days notice and publication of "indicative" tariffs.

The parameters used in the calculation of generation cap (in paragraph 14.15.5 v.)) will be published along with the forecast and confirmed values in the Tariff Information Paper which is produced in compliance with Condition 5 (of the NGC's proposed GB electricity transmission use of system charging methodology - the Authority's decisions document March 2005 80/5).

In addition, The Company will, when revising generation charging zones prior to a new price control period, undertake a zoning consultation that uses data from the latest information paper. The purpose of this consultation will be to ensure tariff zones are robust to contracted changes in generation and supply, which could be expected to reduce the need for re-zoning exercises within a price control period.

[1] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/