nationalgrid

Stage 04: Code Administrator Consultation

Connection and Use of System Code (CUSC)

CMP227

‘Change the G:D split of TNUoS charges, for example to 15:85’

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

CMP227 seeks to change the current 27:73 G:D split, reducing the proportion of TNUoS charges paid by generators.

Published on: 4th June 2015
Length of Consultation: 15 Working days
Responses by: 25th June 2015

High Impact:
All parties which are liable for TNUoS charges

Contents

Any Questions?

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About this document

The purpose of this document is to consult on CMP227 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 which will be furnished to the Authority for their decision.

Document Control

Version	Date	Author	Change Reference
0.1	4th June 2015	Code Administrator	Code Administrator Consultation

1 Summary

1.1 This document describes the Original CMP227 CUSC Modification Proposal (the Proposal), summarises the deliberations of the Workgroup, includes responses to the Workgroup Consultation and describes the Workgroup Alternative CUSC Modifications (WACMs).

1.2 CMP227 was proposed by Intergen and submitted to the CUSC Modifications Panel (the Panel) for their consideration on 28th February 2014. A copy of the Proposal is provided in Annex 1. The Panel sent the Proposal to a Workgroup to be developed and assessed against the Applicable CUSC Objectives. The Workgroup first met on 3rd April 2014. A copy of the Terms of Reference is provided in Annex 2. The Workgroup have considered the issues raised by the CUSC Modification Proposal and, as part of their discussions, the Workgroup has noted that there are a number of potential solutions to the defect that CMP227 seeks to address. These potential options for change are highlighted within the Workgroup Alternatives in Section 5 of this document.

1.3 The Proposal aims to change the G:D split, reducing the proportion of TNUoS charges paid by generators to a suggested ratio of 15:85, which corresponds with the approach modelled under Project TransmiT. The shortfall would be collected from Demand. Under the current structure of the TNUoS charges, the total amount of allowed revenue to be recovered is split between generators and suppliers in the ratio of 27:73.

1.4 The Workgroup Consultation closed on 24th September 2014 and received 18 responses. These responses can be found in Annex 11, a summary of these responses can be found in Section 9 of this report. The final Workgroup meeting was held on 23rd April 2015 and the Workgroup agreed on 5 Workgroup Alternative CUSC Modifications, as set out in the table below:

	Implementation Timescale		
Option	**12m**	**24m**	**36m**
G:D split fixed at 15:85	Original	WACM1	WACM2
G:D split fixed at 4:96 (equivalent to €0.5/MWh at current exch rate)	WACM3	WACM4	WACM5

1.5 The Workgroup voted by majority that WACMs 1, 2 and 5 better facilitate the Applicable CUSC Objectives than the CUSC baseline and by majority that WACM 5 better facilitates the objectives than the original CMP227 proposal. Views as to which option best facilitates the objectives were split across the options and full details of the voting are in section 8 of this Report.

1.6 At the CUSC Modifications Panel meeting on 29th May 2015, the Workgroup Report was presented to the CUSC Panel and the Panel agreed that the Workgroup had met their Terms of Reference and accepted the Workgroup Report. The Panel agreed for CMP237 to progress to Code Administrator Consultation.

1.7 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/CUSC/Modifications/CMP227/.

2 Background

2.1 The latest overview of European transmission tariffs by ENTSO-E issued in July 2014 showed that out of the 34 countries surveyed, 14 have a generator charge and 20 do not, and of those that do, Great Britain now has the highest generator charge at circa €2.5 per MWh. Figure 1 below shows the G components of the unit transmission tariffs in 2014, based on the ENTSOe overview.

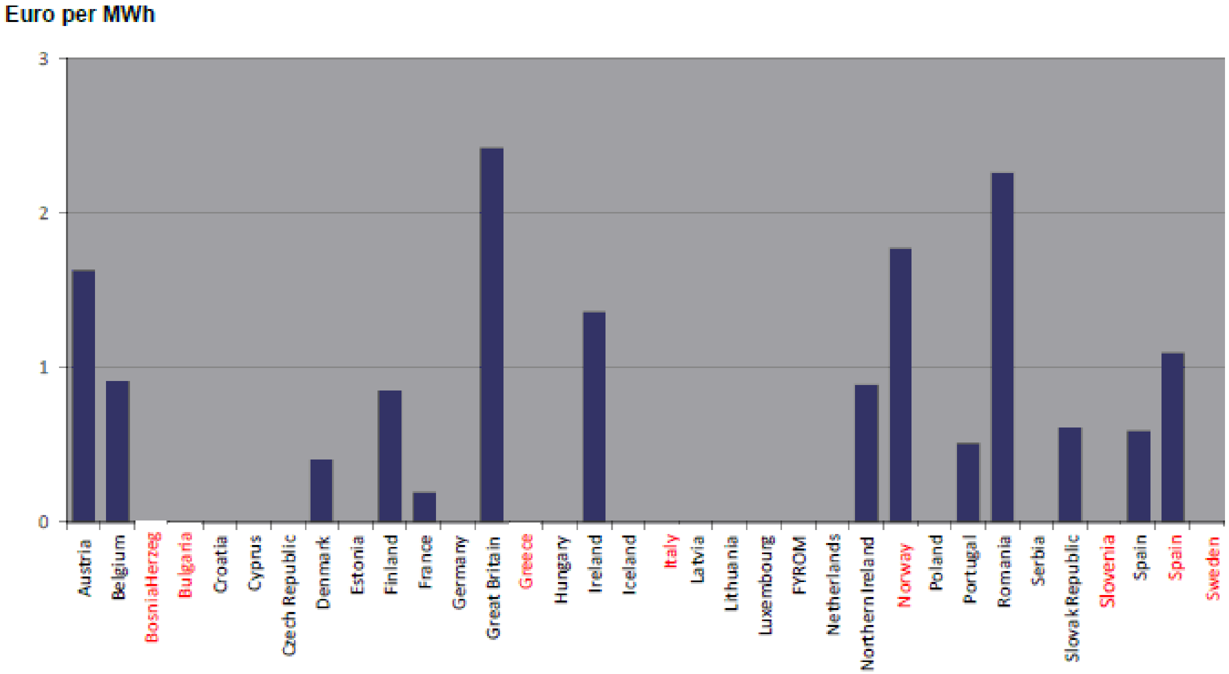

Figure 1 – G component of Transmission tariffs in 2014.

2.2 A review of the G:D split of TNUoS charges was considered as part of Ofgem's Project TransmiT Significant Code Review (SCR). The initial report of the technical working group[1], issued in September 2011, concluded that there were three potential reasons for change in this area;

(i) the relative competitive position of GB generators based in interconnected EU markets;

(ii) the binding EU Tarification Guidelines arising from the Regulation of Cross Border Electricity Exchanges; and

(iii) the proportion of total transmission revenue collected from offshore generators through the local circuit.

2.3 The Project TransmiT technical working group and Ofgem agreed that there could only be a change to the current G:D split arrangements if there was convincing evidence to justify such a change and that the implications had been fully considered. There was consensus that reasons (i) and (ii) above were sufficient to warrant a reduction in the proportion of transmission revenue recovered from generators.

2.4 The Project TransmiT technical working group therefore agreed that in the Project TransmiT modelling scenarios, the generator proportion of TNUoS tariffs should be reduced to 15%, for modelling purposes, to comply with EU Tarification Guidelines[2], and that the reduction would apply from April 2015 to March 2030. It agreed that the most

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[1] https://www.ofgem.gov.uk/ofgem-publications/54282/transmit-wg-initial-report.pdf

appropriate way of changing the split would be a single step change with sufficient notice to allow all parties time to adapt.

2.5 In its conclusion document to the Project TransmiT SCR (issued May 2012), Ofgem decided that a change to the G:D split was not necessary at that time. However, it noted that respondents were broadly split between those who believe that a decision should be taken more immediately and those that thought a change was not necessary at that point. It stated that respondents in this latter group believed that any proposals for change should be progressed through the normal CUSC modification process.

2.6 Ofgem noted that those disagreeing with its view gave two sets of reasons. First there was a concern that the lack of firm policy could lead to regulatory uncertainty and may negatively affect the required adjustment of wholesale power market contracts. Secondly, advocates of reduction in the generator share of TNUoS towards zero argued that such a change would better align GB with its European counterparts, thereby levelling the transmission charging playing field and improving the competitiveness of GB generation in the Single Market.

2.7 Ofgem stated National Grid Electricity Transmission should keep the issue under review and make proposals for change as and when necessary through the normal CUSC modification process. As part of this process, it should consider the EU Tarification Guidelines and the impact on trade between Member States. Subsequently, National Grid raised CMP224 'Cap on the total TNUoS target revenue to be recovered from Generation Users' to take account of EC Regulation 838/2010.

2.8 The development of the Tarification Guidelines, were the subject of consultation by the European Regulators' Group for Electricity and Gas (ERGEG). ERGEG commented that a small generator charge was unlikely to distort competition, particularly within the European continental plate. In relation to other regions already engaged in the harmonisation process, such as the 'Nordic' zone, Great Britain and Ireland complete harmonisation could only be achieved in the long run. Different ranges for the average generator charge would be applied and the ranges re-examined at a later stage.

2.9 In April 2014 the Association for the Cooperation of Energy Regulators (ACER) published an Opinion[3] that "considered it unnecessary to propose restrictions on cost reflective power-based G charges". Previously, the Association had recommended limiting power-based G-charges to €2.5/MWh and this remains the current Regulation 838/2010 as the European Commission is yet to ratify the most recent ACER opinion. ACER is currently undertaking a major study examining whether further harmonisation of the structure of transmission tariffs is required across Europe, and the scoping stage of this work is expected to conclude at the end of 2015.

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[2] Commission Regulation (EU) No. 838/2010 Part B http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF

[3] http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2009-2014.pdf

3 Modification Proposal

3.1 CMP227 seeks to change the split of the total TNUoS charges between generation and demand from the current 27:73 to a lower share of charges for generators, suggested to be 15:85, although other splits could be considered by the CMP227 Workgroup. Once locational charges had been set as per the current methodology, the total charge to generators, being the sum of the locational and residual tariffs, would be set so that the total revenue derived from generators would be 15% of the total allowed revenue in any particular year with the balance (85%) derived from demand. This will be achieved by adjusting the generation and demand residual tariffs.

3.2 This Proposal is aimed at levelling the playing field in Europe in terms of TNUoS charges, enabling GB generators to compete more equitably by reducing or removing a charge that their competitors abroad either do not face at all, or face at much lower cost.

3.3 With the completion of the European internal electricity market due in 2014, the Proposer believes that this proposal would place GB generators in a position where they are no longer unduly disadvantaged against their competitors located in other countries in that internal electricity market.

3.4 In addition, the proposal believes CMP227 would also materially address the issue of predictability of TNUoS for generators charges overall by reducing the exposure of GB generators as a class, who would see a proportionately lower residual charge. This proposal would not change the predictability associated with the locational element of the charge, either under the current charging methodology or under any changes introduced under CMP213 Project TransmiT TNUoS Developments.

3.5 During the Project TransmiT process, the issue of an enduring resolution of the G:D split was raised. Prior to the raising of CMP224 (and CMP227) it had not yet been addressed in the CUSC process, although National Grid has on a number of occasions flagged a need for review to the TCMF.

3.6 The Proposer suggested the ratio of 15:85 to reflect the decision of the Project TransmiT technical working group, although other ratios which lower the generation share could also be considered. It was noted by the Project TransmiT technical working group that the reduction should be sufficient enough to ensure no breach of EU Regulation 838/2010 takes place before 2020 in the ‘worst case’ scenario. The Proposer believes that this is therefore a practical solution that will materially help GB generators in planning their businesses and in competing on a more equal basis in the Single Market.

4 Summary of Workgroup Discussions

Presentation of Original Proposal

4.1 At the first Workgroup meeting, the Proposer presented the background and reasons for raising CMP227. The Original Proposal form can be found in Annex 1 and the supporting presentation can be found on the National Grid Website[4].

Previous Developments

4.2 The Workgroup noted that there had been some previous and ongoing work assessing the G:D split and, as currently set, whether it is appropriate for a future integrated European Electricity Market. The Workgroup was mindful of this during its discussions. The Workgroup considered two CUSC Modifications (CMP201 and CMP224) which were under review when the CMP227 Modification process began, and the work done under the Project TransmiT SCR.

4.3 CMP201 'Removal of BSUoS Charges from Generation' aimed to align the GB electricity Balancing Services charging arrangements with those prevalent within other EU Member States. CMP201 proposed that Balancing Services Use of System (BSUoS) charges, which are currently charged to all liable CUSC Parties on a non-locational MWh basis are removed from GB Generators and recovered 100% from demand; i.e. GB Suppliers. On 2nd October 2014, the Authority chose to reject CMP201.

4.4 CMP224 'Cap on the total TNUoS target revenue to be recovered from Generation Users' aimed 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 current range specified by EC Regulation 838/2010 (€ zero to €2.5 / MWh). CMP224 therefore aimed only to change the G:D split if there was a risk of breaching EC Regulation 838/2010. On 8th October 2014, the Authority decided to approve CMP224 Original Proposal, this was later implemented on 22nd October 2014.

4.5 Under CMP224, 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).

4.6 The CMP224 Workgroup developed the Original Proposal and four Workgroup Alternative CUSC Modifications (WACMs) and agreed that WACM1 would be the best option. WACM1 was based on the annual average transmission charges paid by GB generators including all TNUoS based charges (all local and wider charges); with a cap based on a forecast (with no reconciliation); using a bandwidth (currently calculated as 14%) to manage any forecast error set once; and with a twelve month notice period. On 14th July 2014, Ofgem published a consultation[5] on CMP224. It also set out a minded to position to approve the Original proposal (which differs from (CMP224) WACM1 by using a 7% bandwidth and providing a two month notice period).

4.7 As mentioned in the background to this Report, the Workgroup also noted that the G:D split was also considered as part of the Project TransmiT SCR. The initial report of the technical

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[4] CMP227 Workgroup Information on National Grid website http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP227/

working group issued in September 2011 concluded that there were three potential reasons for change in this area:

(i) the relative competition position of GB generators based in interconnected EU markets;

(ii) the binding EU Tarification Guidelines[6] (regulation 838/2010 – discussed below) arising from the Regulation of Cross Border Electricity Exchanges; and

(iii) the proportion of total transmission revenue collected from offshore generators through the local circuit.

4.8 The Project TransmiT technical working group agreed that in the Project TransmiT modelling scenarios, the generator proportion of TNUoS tariffs would reduce from 27% to 15% to comply with the Tarification Guidelines. It was also agreed that the most appropriate way of changing the split would be a single step change with sufficient notice to allow all parties time to adapt. In its conclusion document to the Project TransmiT SCR issued May 2012, Ofgem decided that a change to the G:D split was not necessary at that time, although some respondents believed that a change should be made sooner rather than later.

4.9 Whilst noting that there are previous and ongoing developments in the same work area, the Workgroup understood that any analysis of CMP227 should be done against the CUSC Baseline which, at that time, did not include changes proposed under CMP201 or CMP224. However, with a decision to approve CMP224 received by the Authority in October, the CUSC Baseline changed during the CMP227 Modification process, after the Workgroup Consultation had closed.

European Commission decision to amend limits set out in EC Regulation 838/2010.

4.10 The Commission Regulation (EU) No 838/2010, Part B, states that;

"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.

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 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."

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[5] https://www.ofgem.gov.uk/publications-and-updates/consultation-connection-and-use-system-code-modification-proposal-224

[6] Commission Regulation (EU) No. 838/2010 Part B http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF

4.11 ACER (the Agency for the Cooperation of European Regulators) carried out a review of the appropriateness of the range of the annual average transmission charges payable by generators across the EU, as set out by the European Commission Regulation 838/2010, beyond December 2014.

4.12 ACER provided its opinion[7] to the European Commission during the CMP227 Workgroup process in April 2014. In summary, it states that;

  - *Energy-based G-charges (€/MWh) shall not be used to recover infrastructure costs; and therefore,*
  - *Except for recovering the costs of system losses and the costs related to ancillary services, where cost-reflective energy-based G-charges could provide efficient signals, energy-based G-charges should be set equal to 0 €/MWh*
- *Different levels of power-based G-charges (€/MW) or of lump-sum G-charges, as long as they reflect the costs of providing transmission infrastructure services to generators, can be used to give appropriate and harmonised locational signals for efficient investments in generation, e.g. to promote locations close to load centers or where the existing grid can accommodate the additional generation capacity with no or minimal additional investments.*
- *The Agency therefore considers it unnecessary to propose restrictions on cost-reflective power-based G-charges and on lump-sum G-charges.*

4.13 For the purpose of this ACER opinion, the following definitions of G-charges apply:

- *Energy-based G-charges are charges payable on every unit of energy produced and/or injected into the grid (€/MWh);*
- *Power-based G-charges are charges payable on the capacity connected to the grid, on yearly or multi-year peak output or output under peak conditions (€/MW);*
- *Lump-sum G-charges are charges that are fixed at the start of the relevant charging period and do not depend on capacity connected, on yearly or multi-year peak output or on output under peak conditions, unless these are taken into account in the form of an average over a past period of at least 5 years. Moreover, lump-sum G-charges may take into account the average annual load factor or the average of other output related factors, as long as such averages are calculated over a minimum of 5 years. The level of the lump-sum G-charge may be differentiated between small and large plants, or based on generator characteristics.*

4.14 The ACER opinion also stated that *"The Agency notes that even power-based G-charges may have significant distortive effects on investment decisions if they are not cost-reflective, lack proposer justification or are not set in an appropriate and harmonised way. Therefore, the Agency will continue to monitor the appropriateness of G-charge levels".*

4.15 At the date of the CMP227 Workgroup Report being published (May 2015) ACER's opinion still stands, however the Commission are yet to respond to the opinion.

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7 http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2009-2014.pdf

4.16 The Workgroup discussed the possible rationale behind the current range of €zero to €2.5 /MWh set out in the EC Regulation. One Workgroup member's view was that this was set higher than other European countries so as to not make such a significant change and force a change to the G:D split within GB at the time it was agreed in 2009/2010.

4.17 One Workgroup member, noting the move to harmonisation set out in Regulation 838/2010, suggested that a potential change to the G:D split would be to base it within the €zero to €0.5 range set in the EC Regulation that is applicable to 21 out of the 28 European member states which would therefore align GB with the majority of other Member States and create a more level playing field between GB generators and those other Member States.

European competition

4.18 It was noted by the Workgroup that currently GB has, according to the ENTSO-E Report, the highest annual transmission charges paid and received by Generators in the EU. Therefore, it was suggested that changing the G:D split to be in line with the majority of European member states would create a more level playing field.

4.19 One Workgroup member pointed out that there is not complete transparency of Generator charges in different European countries and the ENTSO-E report should be treated with a high degree of caution as there was huge variety and complexity in the component costs included in those tariff calculations. Whilst it would appear that other European Generators may not be subject to as high transmission charges as those in GB, they may be subject to other charges that those in GB are not. No account was taken of deep or shallow charging prevalent across European member states, suggesting that if GB were to reduce the generator component of the G:D split, GB generators could be at an advantage over other European Generators. Indeed, paragraph 1 of the report states "a direct comparison of transmission tariffs could be misleading".

4.20 However, another member of the Workgroup noted that ENTSO-E is the body established by EU law that all TSOs are members of and that they (the TSOs) set the transmission charges so they have demonstrable expertise in this area. The report they publish has been produced over a number of years and no deficiencies have been identified by either ACER or the European Commission with it (as they would be duty bound to raise these with ENTSO-E). With respect to deep or shallow charging the Workgroup member noted that ENTSO-E had examined this in detail in their report (Appendix 6 of that report). Notwithstanding that ENTSO-E analysis the Workgroup member noted that ACER had, separately, also examined this and Table 8 in the ACER opinion showed that fifteen Member States (including the UK) had shallow charging and nine had deep charging (and two had none).

4.21 It was also suggested that the Generator component of the G:D split is not the only factor a Generator considers when locating and these other factors should be taken into consideration when deciding on a change to the G:D split. Another Workgroup member disagreed with this, noting that CMP227 deals with GB transmission charging and that, rather than other location factors; such as land costs, fuel availability, staff availability, rates, ease of gaining planning permission etc.; should be the focus.

Rationale for 15:85 G:D split under Project TransmiT

4.22 The Workgroup noted that the 15:85 G:D split proposed under Project TransmiT was modelled by the Project TransmiT technical working group and was linked to the EC Regulation 838/2010 range. It was assumed that under the worst case scenario, a G:D split of 15:85 would ensure GB would not breach the upper range of €2.5 in the EC Regulation before 2020. This was agreed to ensure stability of TNUoS charges in future years.

4.23 One Workgroup member suggested that a potential change to the G:D split should use similar modelling as under Project TransmiT to ensure that GB does not breach the EC Regulation for several years.

Justification for baseline G:D split of 27:73

4.24 The Proposer questioned the rationale behind the current G:D split ratio of 27:73 and the appropriateness of this for the current and future GB electricity market. A Workgroup member stated that the original position, some twenty odd years ago, for setting the G:D split was a ratio of 50:50 where demand and generation would equally contribute towards TNUoS charges. At the time the argument was made that demand is less price elastic than generation and therefore demand should pay 100% of TNUoS charges. However, it was decided to set the G:D Split at 25:75 to include a reduced proportion for generation to reflect the difference in price elasticity. After changes made to the classification of connection assets (PLUGs) in 2004, the connection and infrastructure boundary was modified and, to account for this, the G:D split was amended further to 27:73.

4.25 Some Workgroup members noted that a G:D split of 27:73 was probably not appropriate for the current and future GB market and some options for change were developed.

Impact analysis

4.26 Within the first Workgroup meeting, National Grid were asked to look into the possibility of undertaking some analysis on the impact of a change in the G:D split on wholesale prices and on GB end consumers. National Grid was asked if it could find any common parameters or assumptions made within the analysis performed for CMP201 which could prove helpful in undertaking this analysis. The National Grid representative was unable to find any similarities/assumptions to facilitate this analysis as the analysis done within CMP201 was based on BSUoS short run costs and the analysis required under CMP227 would have to be based on TNUoS long run costs.

4.27 One Workgroup member suggested that although National Grid was unable to undertake this analysis, it was still important for the Workgroup to demonstrate the benefit to/impact on GB consumers to Ofgem. However, another Workgroup member noted that the role of the Workgroup is to assess the Modification against the Applicable CUSC Objectives, and not against other matters such as the Authority's wider statutory duties.

4.28 In broad terms, CMP227 can be expected to increase the TNUoS demand charge element of customer bills, but also lead to reductions in the wholesale price, capacity market clearing price and Contracts for Difference Feed in Tariffs (CfD FiTs) strike prices subject to competitive allocation. These price reductions will reflect the uniform decrease in generator costs resulting from CMP227. These reductions can be expected to offset the increases to customer bills caused by the increase in the TNUoS Demand charge. However, it is important that the change to the G:D split is accompanied with adequate notice to allow prices and costs to adjust efficiently and so avoid windfall gains and losses. It is also expected that CMP227 will alter the terms of trade for generation, bringing GB generators more into line with generators in other European markets which should facilitate the internal market in electricity. By removing a cost distortion to trade between interconnected markets, it could also be expected to increase the probability of delivering benefits of interconnection.

4.29 In terms of the impact on GB consumers, some Workgroup members suggested that the impact is broadly neutral as increased demand TNUoS charges will be offset by reductions in the wholesale price, capacity prices and some CfD FiT strike prices (assuming adequate notice is provided to take into account the prevalence of forward contracting). While the relative competitiveness of GB generation should improve, allowing GB generation to compete on a more equivalent basis with overseas competitors, this could be expected to have a number of resulting impacts. The reduction in generator TNUoS charges would make GB generation more competitive against other European generation and therefore increase demand, initially putting an upward pressure on prices as the marginal plant becomes more expensive. This increase in profitability would provide an incentive for market entry which would then place a downward pressure on prices. The impact from a change in the terms of trade on GB consumers may be broadly neutral, although there is some uncertainty on the precise impact. However, it is expected by levelling the playing field between generators competing in the internal electricity market, this will be beneficial to consumers as a whole throughout the EU Single Market; i.e. through increased allocative efficiency.

4.30 Workgroup members felt that it would be useful to see the impact of modified G:D split ratios on TNUoS tariffs. National Grid agreed to provide this analysis for the year 2016/17 and modified Half-Hourly, Non Half-Hourly and generation TNUoS tariffs for each of the split options described in Section 5 of the report can be found in Annex 4. Calculation of the tariffs includes the new charging methodology approach consistent with implementation of CMP213 which will come into effect in April 2016.

4.31 One Workgroup member calculated an estimated shift in TNUoS costs from generation to demand if there was a change to the G:D Split. For each one percentage point shift in TNUoS costs from generation to demand, this was calculated to equate to a transfer in the order of £26m from generation to demand.

4.32 Once the Workgroup had outlined the potential options for change (outlined in Section 5 of this report) within the third Workgroup meeting, National Grid were asked to conduct tariff analysis on the additional G:D split options; namely (i) €0.25/MWh tariff limit, (ii) transferring the residual tariff from generation to demand and (iii) no G:D Split; this can be found in Annex 4. This tariff analysis was updated following the Workgroup consultation due to an error in the column heading for one of the G:D split options. It should read 18.3:**8**1.7 and not 18.3:**9**1.7.

Cornwall Energy Supporting Analysis

4.33 Within the second Workgroup meeting, the Proposer's Alternate agreed to conduct European Market analysis to present to the Workgroup. As part of this analysis, Cornwall Energy produced a paper on behalf of the Proposer which was circulated to the CMP227 Workgroup. The Proposer's Alternate presented this paper to the Workgroup at the following meeting. The Workgroup did not consider or discuss the paper in detail prior to the Workgroup consultation.

4.34 Cornwall Energy subsequently provided an updated version of their report for the Workgroup Consultation. This paper can be found within Annex 7 of this document. Please note that the Workgroup did not read or contribute towards this report and any views expressed are those prepared by Cornwall Energy for Intergen as Proposer.

4.35 The Proposer's Alternate stated that CMP227 was raised to propose a solution to the fact that other European markets have lower generation transmission charges than those applied in GB. The Proposer's Alternate also acknowledged that transmission tariff comparisons across Europe are very complex and difficult to compare directly. However, the Proposer's Alternate believed that some form of price reallocation between generators and suppliers would provide a benefit to GB consumers.

Impact on Consumers

4.36 The Workgroup also discussed the impact of CMP227 on consumers. One Workgroup member stated that as a result of CMP227, there would be generally lower costs recovered by generators which would mean more competition and more exports, which means that there would be more high cost generation on the GB system and therefore this would increase the cost to consumers. Another Workgroup member noted that if there were high cost generation on the GB system, this would encourage generation to be built in GB which would facilitate competition in generation which should lead to a reduction in costs to consumers. Another Workgroup member noted that GB consumers would not necessarily pay for higher cost generation as the costs of incremental production would be met by European consumers under the New Electricity Trading Arrangements (NETA), but that the fixed costs of generation in GB would be recovered from a wider pool of consumers both inside and outside GB.

4.37 The Proposer's Alternate felt that there should be a move towards a single European electricity market and an important step towards this would be to remove barriers to trade. The Workgroup also noted that compared to the assessment of CMP201, we are in a better position now to assess reallocation of market costs as we know a lot more about government and regulatory policy changes

Consideration of Electricity Market Reform

4.38 The Workgroup noted the importance of considering any interaction with the Electricity Market Reform (EMR) programme when deciding on potential changes to the G:D split ratio. One Workgroup member noted that there would need to be some certainty for generators when putting forward their tender for the Capacity Mechanism.

4.39 Within the third Workgroup meeting, the Proposer's Alternate discussed the potential impacts on CMP227 with the Workgroup and noted that parties that are eligible for the Capacity Mechanism will experience a reduction in costs, if CMP227 were implemented, which will lower capacity market bids and thus the auction clearing price. This should also lower strike prices for those parties applying for CfD FiTs.

Potential options for change

4.40 When developing the CMP227 Proposal the Workgroup developed several options for change to the G:D split. These were loosely based around five potential alternative G:D split ratios. The impact on the tariffs for each of the options can be found in Annex 4.

<u>Updated 15:85 G:D split as modelled under Project TransmiT</u>

4.41 The Workgroup noted that there was modelling undertaken previously under Project TransmiT which resulted in the Project TransmiT technical working group proposing, in 2011, a change to the G:D split to have a new ratio of 15:85. This ratio was set to reflect the range of annual average transmission charges set out in the EC Regulation 838/2010, ensuring that GB did not breach the €2.5/MWh upper limit set out in the regulation before the year 2020. The Workgroup considered the appropriateness of the ratio proposed by the Project TransmiT technical working group and some Workgroup members agreed that whilst the concept seemed appropriate to set a new G:D split ratio, the 2011 proposed G:D split (of 15:85) may now be out of date. The Workgroup asked National Grid to undertake new analysis to find the most appropriate G:D split to update the 15:85 ratio proposed under Project TransmiT with the current assumptions and ensuring no breach of the EU Regulation before the next transmission price control review (2021).

<u>Linked to EC Regulation majority G:D split (currently €0.5/MWh limit)</u>

4.42 The Workgroup agreed that a possible solution for updating the G:D split in line with the CMP227 defect would be to base it on the annual average transmission charges paid by generation in the majority of EU countries. Some Workgroup members felt this created more of a level playing field with European competitors. EC Regulation 838/2010 Part B states

'*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'* meaning that 21 out of 28 countries in the EU have annual average transmission charges paid by Generators of less than €0.5 /MWh. The Workgroup asked National Grid to do analysis to calculate the G:D split ratio assuming annual average transmission charges paid by GB Generators of less than €0.5 /MWh.

4.43 This option has the potential to change depending on the decision made by the European Commission in regards to the ACER opinion on the annual average transmission charges payable by generators across Europe. A decision also needs to be taken on how this option will be implemented in terms of managing £:€ exchange rate fluctuations.

4.44 The Workgroup later decided to split this option into two potential options for change. This would include;

1. linked to an average (€0.25*/MWh)* of the EC Regulation ranges paid by the majority of Member States. (This option results in an average G:D split in GB of approximately 2.5:97.5)
2. linked to the upper limit (€0.5*/MWh)* of the EC Regulation range paid by the majority of Member States. (This option results in an average G:D split in GB of approximately 5:95)

Average 0:100 G:D split

4.45 Some Workgroup members felt that if the G:D split were set to reflect the annual average transmission charges paid by Generators within the majority of Member States, then the Generator proportion of the G:D split should be reduced to zero as this is the case in many Member States.

4.46 One Workgroup member suggested that the Generator proportion of the G:D split should be reduced to zero because of the high price inelasticity of demand and therefore demand should pay for all infrastructure costs and generation should incur other costs such as transmission losses and constraints.

4.47 One Workgroup member recommended that the Workgroup should consider other aspects of European transmission charges if a proposal to change the G:D split to match those of other countries was made as it was suggested that generators in other EU countries incur costs that those in GB do not and therefore this change would not create a level playing field. However, another Workgroup member noted that CMP227 deals with TNUoS charges and not other charges which may, or may not, be faced by generators in some, all or none of the Member States. The Workgroup discussed the level of transparency of TNUoS charges within Europe and whether an accurate comparison could be done.

4.48 A Workgroup member stated that if the Workgroup were to go with a G:D split ratio of 0:100 this would have to be an average charge of zero (or slightly above) as a negative average charge would result in GB breaching the EC Regulation as it currently states *'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'.* Therefore a charge outside this range would not be compliant. However, a Workgroup member noted that it may already be the case that GB breaches as under the status quo GB is the only Member State which has negative TNUoS charges. One Workgroup member suggested that there could be two solutions to ensuring that GB did not breach the EC Regulation. These were either to (i) introduce a bandwidth to avoid the negative charge or (ii) have a mid year tariff change. Some Workgroup members were not supportive of a mid year tariff change.

Generation Residual set to zero

4.49 The Workgroup also discussed the cost reflectivity of current TNUoS charges and suggested transferring the generation residual to demand. It was suggested that the transferring of the generation residual to demand would only work if it is future-proofed by including a floor to prevent negative charges and a cap to prevent average charges rising above €2.5/MWh.

Implementation timescales

4.50 The Workgroup discussed possible implementation timescales for the options outlined above. Whilst some Workgroup members felt changes to the G:D split would need to be implemented as soon as possible, given that this potential for a breach of the EC Regulation has been flagged to industry since 2011, to ensure GB does not breach the EC Regulation, other Workgroup members felt a longer implementation timescale should be used to protect consumers, especially with more significant changes to the G:D split such as the average 0:100 option. Other Workgroup Members noted that as the TNUoS charges paid by generators in GB are already included in the wholesale price, the effect on competition of a change to the G:D split arising from CMP227 should be minimal (if at all) as there would be a corresponding change in the wholesale price.

4.51 The Workgroup discussed the four potential options for change and agreed that implementation should be at the start of the charging year; i.e. 1st April. The Workgroup also agreed to consult on a range of implementation timescales of minimum notice periods given between an Ofgem decision and implementation. The potential notice periods are outlined in the table below as 12 months, 24 months and 36 months;

	12 Months	24 months	36 months
18.3:81.7 (Generation Residual set to zero)	✓	✓	✓
15:85 (Original Proposal)	✓	✓	✓
4.26-95.74 (Average transmission charge equivalent to Euro 0.5/MWh)	✓	✓	✓
2.1-97.9 (Average transmission charge equivalent to Euro 2.5/MWh	✓	✓	✓
0:100		✓	✓

Table 1 - Implementation timescales for possible options for change

4.52 The Workgroup considered the timescales required for the potential changes outlined above and agreed that there should be a choice between 12, 24 and 36 months, although the majority of the Workgroup felt that a more significant ‘average 0:100’ change should require at least 24 months to change so have not included a 12 month timescale within this potential option. One Workgroup member supported more than 36 months’ notice, although after consideration, the majority of the Workgroup felt that this was not necessary.

4.53 The main reason for suggesting implementation timescales of 12 months (excluding the 0:100 G:D split option), 24 months and 36 months is that significant volumes of power are transacted on a forward basis. To avoid windfall gains and losses an adequate implementation timescale is required for wholesale prices to adjust to the lower generator cost base. As forward contracts for power greatly diminish beyond two years ahead it was considered that greater than 36 months' notice was unnecessary. It should be noted that parties will have in excess of 12, 24 or 36 months' notice of the change and this could, ultimately, be up to 23, 35 and 47 months' notice respectively.

4.54 One Workgroup member believed that 24 months' notice would be adequate, but 36 months' notice would be preferred as significant volumes of power are transacted this far ahead of time. Therefore, this amount of notice would be suitable to avoid any windfall gains and losses.

4.55 However, another member of the Workgroup noted that published analysis[8] shows that there is a great volume of trades for near term delivery (day ahead, month ahead) than in the longer term (season ahead, year/s ahead) and that there appears to be no published trades beyond two years out. Given this evidence the Workgroup member questions whether a 36 month notice period could be justified.

4.56 In respect of 'windfall gains and losses' the Workgroup member noted that there is an equally valid proposition that this EC Regulation has been in place since 2009 and that a potential for a breach has been notified to parties since 2011. Therefore by delaying for 12, 24 or 36 months, a change required by law provides a windfall gain to suppliers (by not having to pay for 12, 24 or 36 months what they should by law pay) and a windfall loss to generators (paying for 12, 24 or 36 months something that by law they should not be paying). The Workgroup member observed that the phrase 'windfall gains and losses' tends to be used in the context of why we should delay doing something – it tends to overlook the counter position of the 'losses' faced by those who benefit from the change (and the 'gains' for those who do not benefit from the change) coming into effect when there is a delay in implementation. The Workgroup member noted it also has a further, unintended, consequence, which is to 'reward' not preparing for something we know is coming along and then doing the required change at the last moment and imposing a long transitional period.

Authority decision on CMP201 and CMP224

4.57 In the first post-Workgroup Consultation meeting, the Workgroup discussed the Authority's decision to reject CMP201 and to approve CMP224.

4.58 The Workgroup noted that the Authority had rejected CMP201 because it was not clear that the potential benefits of implementing the Modification would be material enough to offset the costs to consumers.

4.59 A Workgroup member noted that within the CMP201 Authority decision letter, the Authority stated 'The Original proposal is likely in our view to allow sufficient time for suppliers and generators to re-adjust their pricing structures to accommodate this change. We do not have any evidence that an implementation period of longer than two years would change this assessment'. The same Workgroup member stated that if the Authority decided that a 24 month notice period was sufficient for changes to BSUoS charges, this may also be the case with changes to TNUoS charges under CMP227. Another Workgroup member noted that whilst the Authority made this decision under CMP201, BSUoS is a short run marginal cost and TNUoS is a long run marginal cost, so changes to TNUoS charges may have a larger impact on consumers and therefore require a longer notice period.

[8] http://www.energy-uk.org.uk/publication/finish/5-research-and-reports/1069-wholesale-market-report-march-2014.html

4.60 The Workgroup discussed the Authority's decision to approve CMP224 Original Proposal to ensure that GB remains compliant with the EC Regulation 838/2010 and out of the two options presented to the Authority; CMP224 Original has the least impact on demand customers. The Workgroup noted that the Authority has considered WACM1 to best meet the relevant CUSC charging objectives, however, in their view WACM1 would have a larger impact on consumers as it transfers more costs from generation to demand.

4.61 One Workgroup member stated that within their CMP224 Decision letter, the Authority states 'Bringing transmission charges for GB generators more closely into line with those of their EU counterparts should reduce market distortions, which, in principle, should result in more efficient competition between GB and other EU member states and improved competition in the generation of electricity compared with the current baseline' and noted that this is one of the main aims of CMP227.

4.62 The Workgroup noted that the Authority had made it clear within their decision letter the different interpretations of the calculation of G-charges within the EC Regulation that were set out within the CMP224 Final Modification Report. These were;

- 'Strict Interpretation' – only connection charges are excluded from the calculation of the average charge
- 'Broad Interpretation' – connection charges and local charges for radial circuits that supply generators only (Generation Only Spurs) are excluded from the calculation of the average charge.

4.63 Within the decision letter the Authority writes 'we consider that Paragraph 2(1) in Annex Part B of the Regulation is ambiguous and that there is a risk that charges under options that use the broad interpretation are successfully challenged by generators. We therefore consider the options that use the strict interpretation (the original proposal and WACM1) better meet this objective when compared to the options that use the broad interpretation (WACM2 and WACM3).

4.64 The Workgroup agreed that any Workgroup Alternative CUSC Modifications proposed under CMP227 should be consistent with the Authority's interpretation of the Regulation.

Workgroup Consultation Responses

4.65 The Workgroup discussed the key issues and main themes of the Workgroup Consultation responses and used this information to inform their decisions on which options for change to take forward as Workgroup Alternative CUSC Modifications (WACMs). A summary of the individual Workgroup Consultation responses can be found in Section 9 of this report and the full responses can be found in Annex 11.

4.66 The Workgroup noted that out of the 18 responses, the majority of Workgroup Consultation responses were supportive of at least one of the Workgroup's potential options for change, three responses were neutral to the proposal and five responses were against any option being implemented. There was a mixed view of whether the potential options for change better facilitated the Applicable CUSC Objectives.

4.67 The Workgroup recognised that there was a variety of views within the responses on the notice given for changes to the G:D split. Some respondents argued that a shorter notice period for implementation of 12 months would be sufficient for change as it would allow for industry to adjust commercial contracts, would level the playing field within Europe sooner and allow for the realisation of benefits as soon as possible. Whereas, a common trend amongst smaller parties was that a longer notice period for implementation of 36 months was necessary to allow prices and costs to adjust efficiently; it would take account of forward contracting and would avoid a situation where consumers are double charged due to a short implementation timescale.

4.68 The Workgroup discussed appropriate notice periods for changes to the G:D Split. One Workgroup member pointed out that even if there is a short notice period for implementation, the industry should have sight of the possible changes before an Authority Decision, and noted that even though CMP224 was approved by the Authority in October 2014, National Grid were already conducting modelling for this in 2011, as they had done for the CMP227 Origianl of 15:85. Another Workgroup member noted that although this may be the case, smaller parties may not have sight of these changes and reiterated the importance of providing a 36 month notice period after an Authority decision.

4.69 One respondent suggested that if a change would be made to reduce the generator proportion of the G:D Split to 0 (0:100 G:D Split), a gradual approach to change the ratio over a number of charging years would be practical and would minimise the impact on both consumers and generators. The Workgroup also noted that a few respondents had suggested aligning implementation of CMP227 with the introduction of the Capacity Mechanism to ensure that customers can factor in potential TNUoS savings in their Capacity Mechanism bids.

4.70 The Workgroup noted that some respondents thought that implementation of CMP227 would support the retention of existing generation capacity and encourage investment in new capacity; which should in turn reduce costs involved in the Capacity Mechanism. One response referred to the supporting paper, stating that estimated benefits of CMP227 could be between £34mn and £363mn in 2018-19, which would arise from a decrease in Capacity Market costs and reductions in wholesale prices. Whereas, some of the respondents against implementation of CMP227 stated that there could be windfall gains and losses for those already trading their power for 2015 in the market, especially if there is a short notice period for implementation. One respondent noted that CMP227 will cause a direct increase of costs to customers of around £450m per year, or £7 per customer, if implemented from April 2018.

4.71 Some responses noted that competition within the European market should increase as GB will be on more of a level playing field and should have more predictable and stable TNUoS charges than under the current methodology. Other responses considered that there would be a detrimental impact on competition if there was too large a change in the G:D Split or the notice period was too short.

4.72 Some responses suggested that additional analysis should be considered when developing this modification. This included; (i) flow modelling to Europe, (ii) the possible effect on subsidy mechanisms, (iii) security of supply (iv) integration with the European market and (v) the effect on the volatility of charges. One Workgroup member requested that National Grid provides data on how TNUoS charges have changed over previous years. The National Grid representative noted that this is available on the National Grid website.

Further analysis – National Grid

4.73 Following receipt of the Workgroup Consultation responses, the Workgroup agreed to consider several areas of analysis before submitting the Workgroup Report to the Panel.

4.74 The Workgroup discussed who would be best placed to conduct analysis or provide evidence for each suggested topic under the closed economy, trade, risk and security of supply themes. It was agreed that National Grid was best placed to conduct the majority of the analysis with some evidence also to be provided by the Proposer and the rest of the Workgroup. Prior to the next Workgroup meeting, National Grid circulated analysis on these topics to the Workgroup. This included a money flow model, which can be found on the National Grid website[9], and a paper on the requested analysis, which can be found in Annex

[9] CMP227 Workgroup documents http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP227/

5 of this report. There were several questions that National Grid addressed in their analysis, these are;

1. *Are reductions in wholesale prices and reductions in subsidy payments cumulative?*

4.75 The National Grid representative explained how the money flow model works, noting that it shows that a change in the G:D Split may result in lower wholesale prices and capacity mechanism subsidy payments; however, these are offset by an increase in the demand residual. Therefore, any change to the G:D split simply reallocates money between pots, all other things remaining equal. It was observed by one Workgroup member that, should the modification proposal be approved, generators who had already obtained CFDs before approval of the modification proposal would benefit from windfall gains and that therefore to avoid unnecessary market distortions it would be preferable for any decision on the modification proposal to be made quickly.

4.76 It was assumed within the National Grid analysis report that there would be no overall winners or losers due to this. One Workgroup member noted that some generators would pick up a larger cost as they have a greater share in the market therefore increasing their risk. The National Grid representative agreed that the generic high level nature of the model ignores market share differences between market participants.

4.77 A Workgroup member asked whether, if the price of the Capacity Mechanism reduces, there would be a possibility of buying more capacity. The National Grid representative stated that there would be, although the price has already been set at £19.40/kW in 2018/2019, if it was changed before that date, there may be a windfall gain for generators. However, the reduction in generator cost would be expected to result in an equivalent price reduction in the wholesale energy market.

2. *What is the impact on CfDs?*

4.78 The National Grid representative noted that the impact on CfDs is similar to that of the Capacity Mechanism. A lower Generation cost-base may enable a lower strike price, however, any reduction in the generator strike price is offset by an increase in the demand residual and, therefore, of no benefit or disbenefit to GB consumers. One Workgroup member questioned if the Workgroup needed to consider how the money is recovered, as money for the Capacity Mechanism is recovered one way and demand residual is recovered another way.

3. *How long does it take for the market to adjust to changes in TNUoS?*

4.79 The National Grid representative advised that in Ofgem's Market Review analysis, Ofgem suggested that TNUoS changes are passed through at the next contracting round, roughly 18 months later. Some members of the Workgroup agreed that this was a reasonable estimate. One Workgroup member noted that the responses to the Workgroup consultation represented a range of timescales.

4. *How would suppliers pass on charge increases to consumers?*

4.80 The National Grid representative advised that they would expect suppliers to pass through increased costs immediately, or as soon as possible.

5. *What is the differential required to switch interconnector flows?*

4.81 The National Grid representative presented a graph comparing GB, French and Dutch power prices in 2014 and noted that the average price in GB was £42.03/MWh compared to £27.96/MWh in France and £33.22/MWh in the Netherlands. The average differential is therefore £14.41/MWh to France and £8.81/MWh to the Netherlands. Updated data is presented in Annex 10 of this report.

6. Assuming 100% TNUoS transfer to wholesale price, how often would flows be affected?

4.82 The National Grid representative noted that in an open economy (with interconnectors) and all other things remaining equal, GB generators would be receiving a competitive advantage relative to European generators. The National Grid representative considered that it is arguable whether reducing the Generation transmission charge would be a levelling of the playing field or the introduction of a new distortion, given that transmission tariffs are only one feature of the "whole" electricity regime in any given Member State. The majority of the Workgroup thought that the wording 'competitive advantage' within the report could be re-phrased as reducing the Generation charge could create more of a rebalance within Europe. It was noted that it could be seen as a competitive advantage to the status quo, however the Workgroup felt that the wording in the National Grid report should be clarified to say that it changes the cost base as to not imply that generators will be at a competitive advantage over others within Europe.

4.83 One Workgroup member noted that National Grid had looked at the differential in prices in GB and continental hubs, however questioned if this reflected the reality of interconnector flows. The National Grid representative stated that there will be times where the SO from both countries support each other using interconnectors, however this has not been considered within this analysis as SO-SO support is generally independent of prevailing market prices. Another Workgroup member noted that this may have been discussed within the CMP201 Workgroup as interconnectors do sometimes flow the wrong way.

4.84 It was suggested that the analysis should compare the daily profiles rather than a 5 day moving average when looking at the impact on trade.

4.85 One Workgroup member noted the importance of being mindful of the move to the European market model. Based on expected implementation of CMP227, we would expect a change between 2017 and 2020; the market could change substantially within this time. One Workgroup member noted that the Workgroup cannot just look at one component of the energy system with an aim of levelling the playing field within Europe and that all countries have different rights and obligations of which transmission charging is only a small element. The Workgroup member noted that until the government brings in new rules, we cannot start to harmonise the European energy market. Another Workgroup member stated that there is a defect identified in CMP227 that needs addressing and the solution should be based only on that defect and not what other countries are doing or other defects in other areas than charging (which cannot be covered by this CMP227 Modification). The Ofgem representative noted that in discussions within Europe, it is sometimes discussed about having common principles on charging but not necessarily harmonising levels of charges.

4.86 One Workgroup member quoted the Energy and Climate Change Commissioner who said in November 2014 that 'Completing the internal energy market is not just a matter of building interconnections and infrastructure, it also needs new rules. When I say rules – very specifically – we are having problems with network tariffs…The composition of tariffs should be transparent and based on common rules. We have a very complex system of tariffs at the moment'

4.87 One Workgroup member advised that in accordance with EU law the Authority has to be mindful of the benefits to consumers across Europe under the Third Package and not just GB consumers of a particular (GB) change such as CMP227. All things being equal, if a change was detrimental to GB consumers, but beneficial to consumers in the rest of the Union, the Workgroup member believed that the Authority would need to approve that change for the wider societal benefit(s).

7. What is the predictability of TNUoS charges?

4.88 The National Grid representative presented some tables to the Workgroup showing the historical TSO revenues and the generation charging base for years 2008-2015 and how much they have varied in the year leading to the setting of final tariffs. He noted that TNUoS predictability is affected by changes in TSO revenues and tariffs are affected by changes in demand and generation. One Workgroup member suggested that there should be another table included within the report for demand charging. The National Grid representative agreed to include this within the report.

4.89 One Workgroup member felt that the analysis should be separated into new, existing and offshore plant to look at the three different types of charging base. The rest of the Workgroup felt that this was not required. The Workgroup member then noted that the analysis provided should be taken lightly as there is no visibility of the underlying figures.

8. What impact will CMP224 have on predictability of tariffs?

4.90 The National Grid representative noted that CMP224 reduces the predictability of tariffs, but sets a limit on what generation will pay, and therefore when the charges reach the cap, generation has some clarity on final outlay, if it doesn't, any uncertainty is not different to today.

4.91 One Workgroup member noted that there is more of an issue of the demand charges than the predictability of charges because as the generation proportion of the G:D split decreases those charges are being transferred to demand. It was also noted that depending on the volatility of demand charges, this may increase risk and credit requirements for demand TNUoS.

9. How does this proposal change the allocation of risk between suppliers, generators and consumers?

4.92 It was advised that National Grid does not believe that changes in the G:D split have a significant impact on the risk management of tariff volatility. Their main reservation is that as the G:D split is purely an arbitrary number, any change to it potentially opens the door to further debate on the appropriateness of it, which in itself has the potential to cause uncertainty. The Workgroup had no analysis to contribute to this.

4.93 Within the previous meeting, the Proposer also took an action to find out how suppliers would pass on charge increases to consumers by raising the question at the small suppliers' forum. The Proposer noted that there had been no response on this. A Workgroup member suggested that there would be a small proportion of customers with fixed costs to whom you would not be able to pass on charge increases.

4.94 Within the next meeting, the National Grid representative noted that he circulated further analysis on under and over recovery of TNUoS charges modelled under scenarios with 15:85 and 27:73 G:D splits. He noted that the under/over recovery would be greater under a 15:85 G:D split as demand volatility is higher.

Further analysis – Cornwall Energy

4.95 In response to National Grid's analysis, the Proposer submitted further analysis which calculated the impacts of changing the G:D split. As this was first seen by the majority of the

Workgroup during the next meeting, the Workgroup felt that this analysis need to be considered fully before voting on the agreed alternatives to the CMP227 Original.

4.96 The Proposer invited a colleague to dial into this Workgroup meeting to talk through the paper which was submitted to the Workgroup. The Cornwall representative noted a number of assumptions which were outlined within the analysis. One of these assumptions was that TNUoS is a short run marginal cost as generators look to recover their total costs (including TNUoS, maintenance, fuel cost etc.,) through their revenue over the year in their bids into the market.

4.97 A Workgroup member noted that most generators make short to medium term decisions as they would be looking to be cash neutral by the end of plant life.

4.98 One Workgroup member noted that the further analysis suggests that a reduction in the wholesale price is greater than the reduction in TNUoS. For example, a reduction of TNUoS by 2p would reduce wholesale prices by 3p; the Workgroup member questioned who makes up the difference in the prices. The Cornwall representative noted that some parties would lose out under this model, specifically coal and hydro plant. The same Workgroup member noted that even though there is a benefit to marginal generators, there is a cost to others.

4.99 The Cornwall representative also submitted some analysis on Half-Hourly French and British spot prices noting that within the analysis, GB prices were taken from APX and France prices were taken from EPEX spot. This analysis can be found within the Workgroup documents on the National Grid website. The Cornwall representative stated that there would be some scope for early morning exports to France to increase with a reduction in GB wholesale prices. A Workgroup member noted that even though this analysis suggests there would be an increased amount of exports from GB with a reduction in GB wholesale prices, higher exports from GB would probably lead to an increase in GB wholesale prices.

Additional Analysis

4.100 The Workgroup met by teleconference on 3rd March 2015 to conclude its work, complete the remaining actions and hold the Workgroup Vote. However, during the course of the meeting, the Ofgem representative requested additional analysis be completed regarding the impact of a fixed G:D split on TNUoS tariff volatility, compared to a flexible G:D split. The Workgroup agreed that this additional analysis would assist it in considering the potential WACMs they had developed and the National Grid representative agreed to undertake this work on behalf of the Workgroup.

4.101 In addition, the Workgroup discussed correspondence between the Cornwall Energy representative and one of the Workgroup Members' Alternates who held different views on Cornwall's further analysis previously presented and had provided additional information themselves. The Workgroup requested that both of the parties liaise prior to the next meeting to discuss their respective analysis and to present it back to the Workgroup.

Cornwall Energy analysis: CCGT Load Factors

4.102 The Cornwall Energy representative presented his paper (see Annex 7) which looked at two elements related to CMP227: (i) the load factors of marginal plant (CCGTs) and (ii) how generators pass through TNUoS charges into the prices offered into the wholesale power market. He explained that the average CCGT load factor was 44%, while National Grid's model showed an average of 49%. Therefore, assuming the model is correct, then there will be an effect. Cornwall's analysis also showed that vintage CCGTs were below the effect range of 49% (see Figure 2 in the paper).

4.103 As part of this analysis, the Cornwall Energy representative had spoken to a number of parties regarding how they form their prices. His conclusions were that if a party is trading within day or day ahead, their price is based on the short run marginal costs (fuel cost, carbon cost) – this was based on a larger vertically integrated party's view. However, he also noted that smaller parties have different considerations and different arrangements. The Cornwall Energy representative considered that in terms of longer term effects that TNUoS would feed into this as Power Stations will only run if they can cover their costs.

4.104 One Workgroup member questioned how the costs would feed through into the Balancing Mechanism as some CCGTs have extremely high power prices put through into the BM. The Ofgem representative asked whether the analysis shows that there is a limited benefit for CCGTs with a load factor above 49%; the Cornwall Representative agreed with this conclusion. Another Workgroup member noted that a potential issue for discussion by the Workgroup could be specific load factors to take into account for certain CCGT plant, but that it was not possible to identify which marginal prices at specific times. The Workgroup member felt that the Capacity Market would cover off some of the generators' costs. In response, another Workgroup member commented that it was not DECC's intention that the capacity market would allow generators to recover all of their fixed costs.

National Grid analysis: The Impact of a Fixed versus Flexible G:D Split on TNUoS Tariff Volatility

4.105 The National Grid representative summarised his paper (see Annex 9) which looks at charge volatility by looking at historical data with and without a CMP224 type cap, but using a lower cap than the current €2.5/MWh to ensure the cap "bites" over the whole analysis period.

4.106 The National Grid representative explained that he had first considered the expected results from his analysis which he summarised using the figure below:

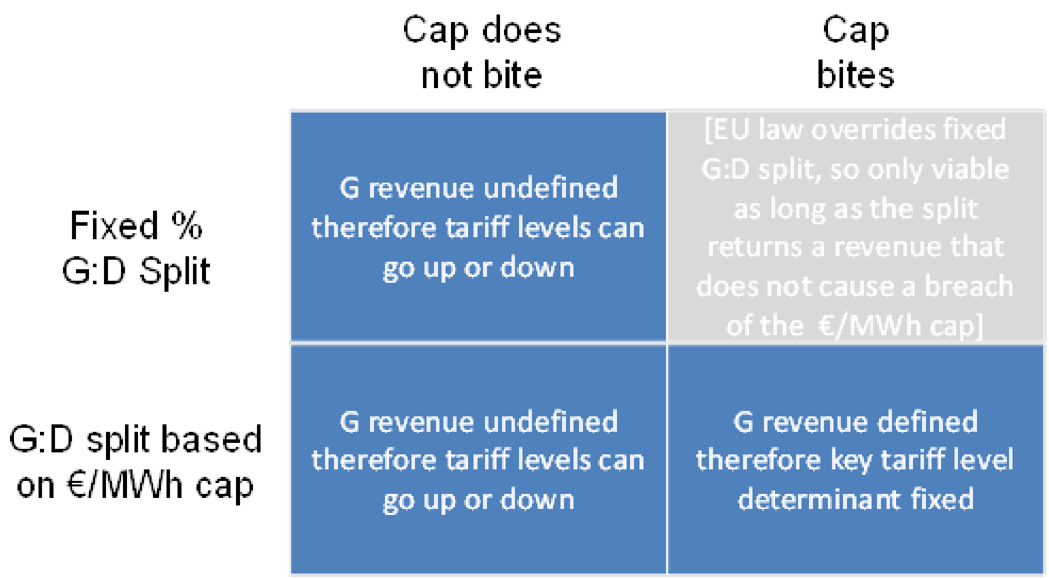


Figure 2

4.107 Having rerun the Transport Model from 2011/12 with the two scenarios above, at both 14 months ahead and 2 months ahead, the National Grid representative concluded that it is not possible to say, looking historically, whether one approach is more stable than the other. One of the Workgroup members noted that this was a helpful conclusion as it suggests that volatility of tariffs is not a valid consideration for the Workgroup.

4.108 One Workgroup member noted the conclusions, but commented that CMP227 seeks to recover more revenue from Demand and therefore there would naturally be more volatility and more risk. Another Workgroup member responded that the risk is whether the overall amount to be recovered will change (e.g. c. £2.5bn) and that there is no immunity to parties from that total risk, just the split of it between different parties. He noted that Generators would seek to pass on their costs and would add a risk premium on. The Proposer noted that if risk in one sector of the industry increases, it may be possible to transfer that risk to another sector. However, another Workgroup member commented that Supplier businesses are already seen as having inflated prices and that further risk premiums would aggravate this position. A possible solution to this was suggested as having longer notice periods for implementation of change, on the grounds that if the regulatory framework is known far enough in advance, consumers will not be disadvantaged by it.

4.109 A Workgroup member suggested that another issue to consider is around how the cap is set, noting that the current €2.50/MWh average cap could change and that if it were written into the charging methodology, GB parties would have greater certainty. The National Grid representative responded that the published ACER opinion is that the cap should be removed, but there has been no ratification from the European Commission of this opinion yet. He clarified that NGET's view is that the result will hang on the work ACER is leading on "tariff structure harmonisation" across Europe. However, this could be a long running piece of work, there is another workshop in June 2015 and scoping should be finished by end of 2015. The Workgroup noted there is a new European Commissioner and that this creates uncertainty over the direction of policy. One Workgroup member raised a concern that ACER's opinion may eventually be implemented and therefore what could be implemented by CMP227 may not be in line with that. The Workgroup Chair noted that the role of the Workgroup is to consider the modification proposal against the existing regulatory background. It was subsequently argued by one Workgroup member that in considering the applicable CUSC Objectives, it is both permissible and desirable to take into account the way in which EU energy market regulation is more likely to develop. Another Workgroup member commented that the outcome of the ACER work on tariff harmonisation would be harmonisation of the structure of tariffs (e.g. ICRP), not the actual level of tariffs.

5 Workgroup Alternatives

5.1 After considering the responses to the Workgroup Consultation, the Workgroup revisited the potential options for change set out in Section 4 of this report and agreed which should be taken forward as formal Workgroup Alternative CUSC Modifications.

5.2 The Workgroup noted that there was a typographical error in the CMP227 Workgroup Consultation for the column heading of one of the G:D split options in the annex 4 table. - (generator residual set to zero), this was previously written as 18.3:**9**1.7 and has since been corrected to 18.3:**8**1.7 throughout the report.

5.3 Initially, the Proposer explained the main principles of the Original proposal as changing the G:D split to 15:85 as it is consistent with Ofgem's analysis for Project TransmiT, with this the Proposer recommended a 12 month implementation timescale.

5.4 The Workgroup then went on to agree 5 potential WACMs under two different G:D splits (the Original and 18.3:81.7 the generator residual set to zero, under different implementation timescales). The Ofgem representative noted that the option of 18.3:81.7 prevents a situation where there is a negative residual charge for generators, and most of the other options will not do this. Based on this, there was majority support for this option to be the basis for three potential WACMs. Following the Workgroup meeting at which this was agreed, the National Grid representative circulated a paper with analysis to show that in their view this was not a viable option (see Annex 5). After considering this analysis, the Workgroup agreed that this was not a viable option and chose not to include it as a formal WACM within the Workgroup report and voted again on which potential options should be taken forward as formal WACMs.

5.5 The Workgroup also discussed whether it was appropriate to include implementation timescales within each WACM or whether they should have a WACM for each G:D split option and allow the Authority to decide the implementation date based on the discussions recorded within this report. It was noted that there may be a risk if there is not an option that the Authority finds appropriate that the report will get sent back or the modification proposal rejected and that there may be a potential need for a four year implementation timescale due to Capacity Auctions. One Workgroup member stated that if Ofgem were to agree a four year implementation timescale this may introduce a precedent for future charging modifications. A Workgroup member noted that the responses to the Workgroup Consultation indicated that the more significant the change to the G:D split, the longer the lead time should be before implementation, and felt that there should be options which include a three year implementation timescale. Another Workgroup member noted that having WACMs for each timescale could be confusing and it may be best to give a view on implementation and let the Authority decide. One Workgroup member disagreed with the concept of a four year implementation timescale as if it were accepted it should be considered in all charging modifications.

5.6 The majority of the Workgroup felt that different implementation timescales should be included within the WACMs within the Workgroup report as this allows stakeholders to respond to the Code Administration consultation in a meaningful way. The Workgroup revisited the potential options for change they had discussed in previous meetings and considered which G:D split options they would like to be put forward as formal WACMs.

5.7 One Workgroup member questioned whether the 4.26:95.74 G:D split was a fixed G:D split that would be written into the legal text. Another Workgroup member clarified that this would not be the case and that the €0.5/MWh is a fixed figure taken from the EU Regulation and this would be used to calculate the G:D split, like it is now with the €2.5/MWh limit introduced into the CUSC by CMP224. A Workgroup member then noted that if this is the case, it should be referred to as G:D split set to €0.5/MWh. The Workgroup felt these were both viable options and decided to include them as formal WACMs, however noted that the split based on €0.5/MWh should be updated as the £:€ exchange rates have changed significantly recently. There was not majority support for any other G:D split.

5.8 The National Grid representative put forward an option of a 48 month lead time for implementation, which did not receive majority support from the Workgroup. The Chair saved the option of 48 months for all G:D split options and the Workgroup agreed the WACMs should be set out as follows:

Table 2: Potential WACMs

	12 month	**24 month**	**36 month**	**48 month**
15:85 G:D Split	Original Proposal	WACM1	WACM2	WACM3
4.26:95.74 G:D Split (fixed)	WACM4	WACM5	WACM6	WACM7
Split based on €0.5	WACM8	WACM9	WACM10	WACM11

5.9 At its final Workgroup meeting, the Workgroup members revisited the WACMs they had previously agreed in light of the additional analysis undertaken by National Grid and Cornwall Energy (see section 4 for details). The Workgroup considered the potential WACMs set out in Table 2 above and provided their views as to whether each potential WACM better facilitated the Applicable CUSC Objectives than either the CUSC baseline or the Original CMP227 proposal. Having concluded their discussions, only potential WACM1 as set out in the table above received majority Workgroup support to be progressed. The Workgroup then looked to the Workgroup Chair to see whether she wished to progress any of the proposed alternatives in line with the process set out in the CUSC. The Workgroup Chair considered the views provided by Workgroup Members against the Applicable CUSC Objectives and the level of support from Workgroup members for each of the other options and elected to progress potential WACMs 2, 8, 9 and 10 as shown in the table above. Following this process, the final agreed WACMs are as follows:

Table 3: Final Agreed WACMs

Implementation	**12m**	**24m**	**36m**
G:D split fixed at 15:85	Original	WACM1	WACM2
G:D split fixed at 4:96 (equivalent to €0.5/MWh at current exch rate)	WACM3	WACM4	WACM5

6 Impact and Assessment

Impact on the CUSC

6.1 Changes will be required to Section 14, Part 2 – Section 1, The Statement of Use of System Charging Methodology. Please see Annex 12 for the proposed legal text.

Impact on Greenhouse Gas Emissions

6.2 None identified.

Impact on Core Industry Documents

6.3 None identified.

Impact on other Industry Documents

6.4 None identified.

7 Proposed Implementation and Transition

7.1 The Workgroup assumption is that, if implemented, the Proposal will come into effect at the start of the charging year (i.e. 1st April) after an agreed notice period following Authority decision. The Workgroup have considered and consulted on the options of 12, 24 and 36 months. To clarify, this means:

a) Implementation on 1st April following 12 months after an Authority Decision.

b) Implementation on 1st April following 24 months after an Authority Decision.

c) Implementation on 1st April following 36 months after an Authority Decision.

7.2 For clarity, and assuming an Authority decision on or prior to 31st March 2016, then the above options would be implemented on:

a) 1st April 2017

b) 1st April 2018

c) 1st April 2019

8 Views

Workgroup view

8.1 The Workgroup believes that the Terms of Reference have been fulfilled and that CMP227 has been fully considered. On 23rd April 2015, the Workgroup voted by majority that WACMs 1, 2 and 5 (as shown in Table 3) all better facilitate the Applicable CUSC Objectives than the CUSC baseline. In addition, the Workgroup voted by majority that only WACM 5 is better than the CMP227 Original. Views were split across the Workgroup as to which of the options best facilitates the Applicable CUSC Objectives, as set out in the tables below.

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.

National Grid initial view

8.3 National Grid considers that none of the options proposed better facilitate the Applicable CUSC Objectives than the CUSC baseline. With regard to objective (a), NGET does not believe that changing the G:D split alone better facilitates competition with European generators. All Member State electricity regimes should be considered on a holistic basis, including firmness of access rights, deep/shallow charging, capacity mechanisms, carbon floor prices, balancing services remuneration and renewable support mechanisms. By not considering these other factors, arbitrarily changing the G:D split risks introducing a new distortion. With regard to objective (b), National Grid considers that the G:D split is an arbitrary number and no split is preferable over any other, therefore changing the split neither improves nor worsens cost reflectivity. However, National Grid believes that the industry should be mindful that reducing the generation residual and increasing the demand residual could result in the GB consumer part funding any consequential additional exports to Europe, resulting from a lower generation cost base. National Grid notes that, in respect of objective (c), the last ACER opinion indicated that it wishes to remove restrictions on power-based Generation charges, though this has not yet been ratified by the EC. However, other Member States are introducing power-based Generation charges and other countries could very soon be implementing power-based Generation charges against a background of falling demand charging bases. With regard to objective (d), National Grid notes that the existing arrangements implemented by CMP224 are legally compliant and therefore the impact of CMP227 is neutral.

Workgroup vote

8.4 The Workgroup met on 23rd April 2015 and voted on the Original proposal and the 5 Workgroup Alternative CUSC Modifications (WACMs) shown in Table 3. One Workgroup member was unable to attend the meeting and passed his vote to a fellow Workgroup member prior to the meeting, as shown in the three tables of votes below. The votes received are as follows:

Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives

WG Member	Original	WACM1	WACM2	WACM3	WACM4	WACM5
Cem Suleyman	No against (a)	Yes	Yes	No	No	Yes
Garth Graham	Yes against a – d	Yes against a – d	Yes against a – d	Yes against a – d	Yes against a – d	Yes against a – d
Guy Phillips	No	Yes against a	Yes against a	No	No	No
James Anderson	Yes against a	Yes against a	Yes against a	Yes against a	Yes against a	Yes against a
Jon Wisdom	No	Yes against a	Yes against a	No	No	Yes against a
Nick Pittarello	No	No	No	No	No	No
Paul Brennan	Yes	Yes	Yes	Yes	Yes	Yes
Paul Mott (via Garth)	No	No	No	No	No	No
Robert Longden	Yes	Yes	Yes	Yes	Yes	Yes
	Yes = 4 **No = 5**	**Yes = 7** No = 2	**Yes = 7** No = 2	Yes = 4 **No = 5**	Yes = 4 **No = 5**	**Yes = 6** No = 3

8.5 As shown in the table above, the Workgroup voted by majority that WACM 1, WACM 2 and WACM 5 all better facilitate the Applicable CUSC Objectives than the CUSC baseline. The CMP227 Original proposal, WACM3 and WACM4 were considered, by a narrow majority, to not better facilitate the objectives, when compared to the CUSC baseline.

Workgroup comments:

8.6 **Cem Suleyman:** Views are against objective (a) only, in terms of whether the proposals better facilitate the European single market. The 15:85 split gets us some way to being more comparable to European markets, based on the evidence in the ENTSO-e report. The 4:96 split gets us closer to parity. For the 15:85 split, 24 months' notice is adequate. The proposals are neutral against objectives (b), (c) and (d).

8.7 **Garth Graham:** All of the options better facilitate the CUSC objectives than the CUSC baseline. Against objective (a) they better facilitate competition in Europe, by addressing the defect in CMP227 and remove the situation whereby GB generators are disadvantaged. Against objective (b), they better reflect costs that generators incur. Objective (c) follows on from objectives (a) and (b) and the proposals are better against objective (d) by better facilitating compliance with legally binding decisions of the Commission as the baseline national code arrangements affect cross-border trade.

8.8 **Paul Mott (via Garth):** None of the options better facilitate the CUSC objectives as compared to the baseline, due to arbitrary nature of changes proposed.

8.9 **Guy Phillips:** The Original proposal gives insufficient time for parties to implement the change. Against objective (a), WACMs 1 and 2 gives parties sufficient time to respond and, against the current baseline, provide greater certainty of split and parties have more foresight. In NGET's 5 year forecast published in January 2015, Table 19 gives an idea of how the G:D split might go. WACMs 3 to 5 go too far, there is no onus on GB to move to that level of split (relative to objective d), and may be detrimental to objective (a). Could result in an increase in negative generation charging which could call into question the basis of the charging methodology due to proliferation of negative charging, for cost recovery reasons.

8.10 **James Anderson:** Objective (a) is key for this proposal, GB is not on a level playing field in a world of interconnections and both options go some way to addressing this. The proposal is neutral on cost reflectivity as it does not alter the relative charges of generators to each other. Against objective (c), CMP227 marginally improves against greater interconnection, but is largely neutral. Until we have a binding EU regulation, it is neutral against objective (d).

8.11 **Jon Wisdom:** The implementation timescale for the Original proposal is too soon so will detrimentally affect competition; WACMs 1 and 2 allow the market to react and so can be considered okay. Objective (c) is not better facilitated by any of the options as it is pre-empting potential decisions from Europe. The proposals are neutral against objective (d).

8.12 **Nick Pittarello:** Objective (a) not facilitated as split is same for all generators. NGET does not believe changing G:D split alone better facilitates competition with European generators. All Member State electricity regimes should be considered on a holistic basis, including firmness of access rights, deep/shallow charging, capacity mechanisms, carbon floor prices, balancing services remuneration and renewable support mechanisms. By not considering these other factors, arbitrarily changing the G:D split risks introducing a new distortion. Objective (b): G:D split is an arbitrary number, no split is preferable over any other, therefore changing the split neither improves nor worsens cost reflectivity. However, we should be mindful that reducing the generation residual and increasing the demand residual could result in the GB consumer part funding any consequential additional exports to Europe, resulting from a lower generation cost base. Objective (c): the last ACER opinion indicated it wishes to remove restrictions on capacity based G charges, thought this has not yet been ratified by the EC. Other Member States are introducing G charges, so other countries could very soon be implementing G charges against a background of falling demand charging bases. ACER is reviewing tariff harmonisation, changing the split now doesn't take account of these possible future developments. Objective (d): existing CMP224 arrangements are legally compliant and therefore the impact of CMP227 is neutral.

8.13 **Paul Brennan:** All of the proposals are better than the baseline as they facilitate competition. Against objective (b) there is marginal deterioration against cost reflectivity as the costs are not targeted in same way at particular players, recognising this is limited difference due to increases in negative charging. The proposals also reflect developments in the transmission business for greater interconnection with Europe. Neutral against objective (d).

8.14 **Robert Longden:** The proposals are better against objective (a) as they are supportive of competition and wider European competition; they provide certainty of split for forward planning. The proposer believes that consumers would not be disadvantaged by a change in the G:D split as any increase in exports to the continent would lead to a reduction in average costs for marginal generators and a resulting reduction in the wholesale price of energy, reflected through the competitive generation market.

Vote 2: whether each WACM better facilitates the Applicable CUSC Objectives than the Original

WG Member	WACM1	WACM2	WACM3	WACM4	WACM5
Cem Suleyman	Yes	Yes	No	No	Yes
Garth Graham	No	No	Yes	Yes	Yes
Guy Phillips	Yes	Yes	No	No	No
James Anderson	No	No	No	Yes	Yes
Jon Wisdom	Yes	Yes	No	No	Yes
Nick Pittarello	No	Yes	No	No	Yes
Paul Brennan	No	No	Yes	Yes	Yes
Paul Mott (via Garth)	No	No	No	No	No
Robert Longden	No	No	No	No	No
	Yes = 3 **No = 6**	Yes = 4 **No = 5**	Yes = 2 **No = 7**	Yes = 3 **No = 6**	**Yes = 6** No = 3

8.15 **Cem Suleyman:** WACMs 1, 2 and 5 are better than the Original against objectives for reasons previously given. 12 months is too short an implementation timescale for either option. WACM4 is not better than baseline because it is a more drastic change than the original.

8.16 **Garth Graham:** WACMs 1 and 2 are not better than the Original as a shorter lead time is better. WACMs 3, 4 and 5 are better as 4:96 is better than the 15:85 split in the Original.

8.17 **Paul Mott (via Garth):** The splits proposed are arbitrary, so not supportive of any of the options.

8.18 **Guy Phillips:** For the same reasons as provided in Vote 1, the implementation timescales are beneficial for 15:85. A 12 month implementation timescale is preferable for 15:85 than a longer implementation timescale for 4:96.

8.19 **James Anderson:** My preference is for the 4:96 split, but 12 months is too short for implementation. 15:85 can be implemented in 12 months, no need to wait for 24 or 36 months.

8.20 **Jon Wisdom:** WACMs 1 and 2 are better because they give more notice to the market for change. WACM5 is better because even though it is a steeper change, it gives the market more notice. WACMs 3 and 4 are not better due to steeper change and shorter timescales.

8.21 **Nick Pittarello:** Although I do not like any of the options, WACMs 2 and 5 are better than the Original because they give more notice of the change.

8.22 **Paul Brennan:** WACMs 1 and 2 are not preferable as they delay a good change. I would also like to record my view that Ofgem should make a decision quickly. WACMs 3, 4 and 5 are all better as they address the problem more substantially.

8.23 **Robert Longden:** Without further information regarding the impact of potential greater negative charging for the 4:96 option, it is not possible to say whether this is preferable to the Original, therefore all options not better than Original.

Vote 3: Which option is best? (Baseline, Original, WACM1, WACM2, WACM3, WACM4, WACM5)

WG Member	Best option	Rationale
Cem Suleyman	WACM 5	Gets the right result, but implementation scale is compatible with ensuring no detrimental impact on competition in GB
Garth Graham	WACM 5	As above
Guy Phillips	WACM 1	Preference for 15:85 split and certainty over split, 24 months sufficient time for market to respond
James Anderson	WACM 4	4:96 split but with 24 months' notice
Jon Wisdom	Baseline	
Nick Pittarello	Baseline	
Paul Brennan	WACM 4	Objective (d) – slight concern about negative charging for generators, but no problem against objective (d).
Paul Mott (via Garth)	Baseline	
Robert Longden	Original	As Proposer, I support the Original.

9 Workgroup Consultation Responses

9.1 Eighteen responses were received to the Workgroup Consultation. These responses are contained within Annex 11 of this report. The following table provides an overview of the representations received;

Company	Views against Applicable CUSC Objectives (ACO's)	Support Implementation approach?	Other comments
Banks Renewables Ltd	Yes, all better than the baseline.	1st April 2016.	No.
British Gas	No objectives are better facilitated by the CMP227 Proposals.	Minimum notice of 3 years is necessary.	No.
E.ON	Yes to (a) and (d) – but only with appropriate implementation notice.	2 years notice period.	No.
EDF Energy	CMP227 slightly worse facilitates ACO's. G:D Split discussions should be had within the European Tarification Guidelines.	Minimum notice period of 2 years required.	No.
Energy UK	Provides links to ACO (a). CMP227 proposals require a holistic approach and assessment to remove barriers to competition.	Minimum notice period of 2 years required.	There is a considerable amount of volatility in National Grids TNUoS forecasts. Would consider it appropriate to review the impact of regular changes in the G:D split arising from CMP224 against the static charges that CMP227 would offer.
ESB	Supportive of the principle. Agree with the suggested WACM of 0:100 G:D split.	Any change should be made on 1st April. 12 month notice period to avoid breach of EU regulations.	Would encourage further assessment and industry wide discussion of how best to manage TNUoS volatility.
Fred Olsen Renewables Ltd	All options better facilitate ACO's than the baseline.	1st April 2016. It gives enough notice and the change can be reflected in CfD strike prices.	No
Gazprom Energy	No options better facilitate ACO's. If a change is made there should be at least 36 months' notice.	1st April 2018 at the earliest.	No
GDF Suez	Yes, we support reducing the G proportion of the G:D Split.	12-24 months.	No
Haven Power	Not enough justification to	No comment	This modification will

Company	Views against Applicable CUSC Objectives (ACO's)	Support Implementation approach?	Other comments
	move to G:D ratio of 0:100. Other options will meet objectives and have less impact.		have different impacts depending on the size and business model of parties. We do not think this has been considered when discussing implementation timescales.
InterGen	All options are better than the baseline, the best option is 0:100.	1st April 2016. At least one full charging year's notice, but earliest possible realisation of benefits.	No
Opus Energy Ltd	No. We have 3 year contracts for which the costs are fixed.	Require 3 years notice for changes.	No
REA	Yes, strongly supportive of proposals.	Yes	We believe this is a logical step for the UK market and enables greater competition at no added cost to the consumer.
RWE Npower	None of the options better facilitate ACO's, however, if any option were to be implemented, 15:85 would be preferred.	24-36 notice period would allow for the effective pass through of costs into consumer prices and to ensure there is no double charging as a result of this allocation.	No
Scottish Power	All options better facilitate ACO's better than the baseline.	24 months' notice is sufficient, although earliest possible implementation is best.	No
Smartest Energy	All options better facilitate ACO's better than the baseline.	Do not support implementation, however minimum 2 years lead time is required.	Not in favour of this modification as it has not been justified.
SSE	All options could better facilitate the ACO's.	12 months' notice.	No
VPI Immingham	We are supportive of the option 15:85	1st April 2016 (12 months' notice).	The proposed changes will help GB generators to compete and therefore they are more likely to stay open.

9.2 The Workgroup discussed the Workgroup Consultation responses in some detail in order to agree on the best options for WACMs to be provided to the Authority alongside the Original

Proposal. The Workgroup discussions based on the Workgroup Consultation Responses can be found within Section 4 of this report.

10 How to Respond

10.1 If you wish to respond to this Code Administrator Consultation, please use the response pro-forma which can be found under 'Industry Consultation' via the following link;

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP227/

10.2 Responses are invited to the following questions;

1. **Do you believe CMP227 or any of its alternative solutions better facilitates the Applicable CUSC Objectives? Please include your reasoning.**

2. **Do you support the proposed implementation approach as set out in Section 7? If not, please state why and provide an alternative suggestion where possible.**

3. **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 **25th June 2015**. 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 this 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'.

11 Glossary

ENTSO-E: European Network of Transmission System Operators for Electricity

TNUoS: Transmission Network Use of System

TCMF: Transmission Charging Methodologies Forum

SCR: Significant Code Review

BSUoS: Balancing Services Use of System Charges

ACER: Agency for the Co-operation of Energy Regulators

CFD FiTs: Contracts for Difference Feed in Tariffs

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP227

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal

Reduce the G:D split of TNUoS charges, for example to 15:85

Submission Date

18th February 2014

Description of the Issue or Defect that the CUSC Modification Proposal seeks to address

Under the current structure of TNUoS charges the total amount of allowed revenue to be recovered is split between generators and suppliers in the ratio 27:73. An initial split of 25:75 was set in place at vesting, but changes to the connection/grid boundary resulted in this subsequently moving to 27:73.

This split and the share of charges borne by generators in Great Britain is significantly out of line with levels of charges for grid use paid by generators in most other jurisdictions that fall under the Single Target Market for electricity. This has a distorting impact on competition and works to the detriment of GB generators as their higher charges put them at a competitive disadvantage. The majority of European countries do not charge use of system charges to generators and, where they do, all except Ireland and Romania are at a lower level.

The proposal would change the G:D split, reducing the proportion of TNUoS charges paid by generators. It is suggested that the reduction is to a split of 15:85, which corresponds with the approach modelled under Project Transmit. However, other splits which reduce the proportion of TNUoS charges paid by generators could also be considered by the workgroup.

The direct consequence of the proposal would be to level the playing field with generators in other European countries. This would facilitate competition in generation in the wider European market through improved harmonisation of the regulated costs faced by generators in different countries. It would also be a timely move given the growing momentum towards implementing the internal energy market which is planned to be completed this year.

Not implementing the proposal will mean that GB generators are increasingly disadvantaged against their European competitors as the European market continues to develop.

The impact on suppliers and therefore consumers is expected to be neutral. Vertically integrated generators will reflect the reduced TNUoS charges in the wholesale costs borne by their retail businesses whereas an overall reduction in TNUoS charges for generators will prevent the mothballing of gas plant owned by independent generators. The continued operation of these plants will therefore support wholesale price stability, promote competition in the generation sector and ensure security of supply.

As stated, the main purpose of the proposal is to seek a more level playing field with European generators. A further consequence is that the proposal would also improve the predictability of TNUoS charges for generators and reduce the risk of unexpected shocks.

At the zonal level TNUoS charges have proved to be very difficult to predict over recent years, with individual generators seeing significant changes in the charges they are asked to pay year-on-year. Given that the current level of the charge makes it a significant business cost, it makes planning more difficult and uncertain and also introduces an unnecessary element of risk for generators looking to enter into long-term contracts. By reducing the level of charges paid by generators as a class, the proposal would significantly reduce this impact on generators. A more predictable charging background would help facilitate investment and therefore competition.

Suppliers would bear an increased proportion of the TNUoS costs. However, suppliers are less exposed to changes to locational charges: as demand zones cover larger and different areas to the generation zones. Suppliers are also exposed to a higher proportion of their charge made up by the residual charge. Changes therefore tend to be smoothed out when compared to generation changes. Therefore the proposal should result in an overall increase in certainty of charges across generation and supply.

A further additional benefit of the modification proposal is it would address the current uncertainty over the future of the G:D split. There are two particular aspects to this uncertainty:

First, in 2012 an industry working group suggested a revised split should be implemented as part of Project Transmit largely on competition grounds owing to GB practice being out of line with virtually all of our European neighbours. On that occasion Ofgem noted the case for change but asked that the CUSC Panel keep the matter under review;

Second, National Grid has itself brought forward a change proposal, CMP224 *Cap on the Total TNUoS Target Revenue to be Recovered from Generation Users*, which is currently under-going assessment, which could result in a limited rebalancing of charges away from generators in the event that average charge to generators expressed in €/MWh exceeded a threshold of €2.50/MWh.[1] Our proposal to reduce the share of TNUoS charges faced by generators could address in a straightforward way the issue of TNUoS generation charges remaining within the *Tarification Guidelines*, depending on the European Commission's decision following ACER's review of the current required range for generation charges.[2]

More generally this issue of the split has consistently been at the top of the list of issues to address compiled by National Grid from members of the Transmission Charging Methodology Forum (TCMF). If this issue is not addressed, it will continue to be a source of regulatory risk and therefore to act to the detriment of competition between generators.

Description of the CUSC Modification Proposal

Background

The latest overview of European transmission tariffs by ENTSO-E issued in June 2013 demonstrates that GB is an outlier in terms of the level of transmission tariffs. Of 32 countries surveyed over half had no generator component but only two (Ireland and Romania) paid levels higher than GB. 'ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2013' report can be found at the following link;
https://www.entsoe.eu/fileadmin/user_upload/_library/Market/Transmission_Tariffs/Synthesis_2013_FINAL_04072013.pdf

The G:D split of TNUoS charges was considered as part of the *Project Transmit Significant Code Review*. The initial report of the technical working group issued in September 2011 concluded that there were three potential reasons for change in this area:

(i) the relative competitive position of GB generators based in interconnected EU markets;

(ii) the binding EU *Tarification Guidelines* arising from the *Regulation of Cross Border Electricity Exchanges*; and

(iii) the proportion of total transmission revenue collected from offshore generators through the local circuit.

The workgroup and Ofgem agreed there could only be a change to the current G:D split arrangements if there was convincing evidence to justify such a change and the implications had been fully considered. There was consensus that reasons (i) and (ii) were sufficient to warrant a reduction in the proportion of transmission revenue recovered from generators.

The workgroup therefore agreed that in the Project Transmit modelling scenarios the generator proportion of TNUoS tariffs would reduce to 15% to comply with *Tarification Guidelines*, and that the reduction would apply from April 2015 to March 2030. It agreed the most appropriate way of changing the split would be a single step change with sufficient notice to allow all parties time to adapt.

The Project TransmiT: Electricity Transmission Charging Significant Code Review Initial Report of the Technical Working Group (2011) can be found via the following link;
https://www.ofgem.gov.uk/publications-and-updates/project-transmit-electricity-transmission-charging-significant-code-review-initial-report-technical-working-group

In its conclusion document to the Project Transmit *Significant Code Review* issued in May 2012 Ofgem decided that a change to the G:D split was not necessary at that time. However, it noted that respondents were broadly split between those who believed that a decision should be taken more immediately and those that thought a change was not necessary at that point. It said respondents in this latter group believed that any proposals for change should be progressed through the normal amendment process.

The regulator noted that those disagreeing with its view gave two sets of reasons. First there was a concern that the lack of firm policy could lead to regulatory uncertainty and negatively affect the required adjustment of wholesale market contracts. Secondly, advocates of a reduction in the generator share towards zero argued that such a change would better align the UK with its European counterparts, thereby levelling the transmission charging playing field and improving the competitiveness of GB generation in Europe.

Ofgem said National Grid Electricity Transmission should keep the issue under review and make proposals for change as and when necessary through the normal amendment process. As part of this process it should consider the *EU Tarification Guidelines* and the impact on trade between Member States.

The Project Transmit SCR conclusions document (2012) can be found via the following link; **https://www.ofgem.gov.uk/ofgem-publications/54066/transmit-scr-conclusion-document.pdf**

The development of the *Tarification Guidelines*, which were consulted on by ERGEG which provided recommendations to the European Commission, indicates that the direction of progress is towards lower generator charges. It commented that a small generator charge was unlikely to distort competition, particularly within the European continental plate. In relation to other regions already engaged in the harmonisation process, such as the "Nordel" zone, Great Britain and Ireland complete harmonisation could only be achieved in the long run. Different ranges for the average generator charge would be applied and the ranges re-examined at a later stage.

The comments on the proposal of guidelines on transmission tariffs drafted by the European Commission (2004) can be found via the following link; **http://ec.europa.eu/energy/electricity/florence/doc/florence_11/ergeg_g_and_l.pdf**

The explanatory on the guidelines on transmission tariffs (2005) can be found via the following link; **http://www.ceer.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/ELECTRICITY/Transmission%20Tarification%20Guidelines/CD**

Proposal

This modification would change the split of total TNUoS charges between generation and supply from the current 27:73 to a lower share of charges for generators, suggested to be 15:85, although other splits could be considered by the workgroup. Once locational charges had been set as per the current methodology, the total charge to generators made good by the residual charge applied to generators would be set so that the total revenue derived from generators would be 15% of allowed revenue in any particular year.

The proposal is aimed at levelling the playing field in Europe, enabling GB generators to compete more easily by reducing or removing a charge that their competitors abroad either do not face at all, or face at much lower levels.

With the completion of the European internal energy market due this year, the proposal is very timely. Looking ahead to a more integrated European market the proposal would place GB generators in a position where they are no longer disadvantaged against their active competitors in other countries.

In addition the proposal would also materially address the issue of predictability of TNUoS charges overall by reducing the exposure of generators as a class, who would see a proportionately lower residual charge. The proposal would not change the predictability associated with the locational element of the charge, either under the current charging methodology or under any changes introduced under CMP213 *Project Transmit TNUoS Developments*.

The proposal would also remove the uncertainty arising from the widely perceived need to address this issue and provide an enduring approach, fixing the G:D split going forwards.

Although raised in the Project Transmit process, the issue of an enduring resolution of the G:D split has not yet been addressed in the CUSC process, though National Grid has on a number of occasions flagged a need for a review to TCMF.

The ratio 15:85 has been suggested to reflect the decision of the Project Transmit technical workgroup, but other ratios which lowered the generator share could also be considered. It was noted by the group that this reduction would be sufficient to ensure no breach of Regulation 838/2010 took place before 2020 in the "worst case" assumption. This is therefore a practical solution that will materially help generators in planning their businesses and in competing on the European playing field.

Implementation

Implementation is suggested to be after not less than one full charging year after an Authority decision to allow for industry adjustment of commercial agreements or 1 April 2016 (whichever is the earlier). Given the notice provided by this change proposal, this would also provide suitable notice of change to generators in the planning, consenting or building phase.

Impact on the CUSC

The proposal would impact *Section 14 Part 2 - Section 1 The Statement of Use of System Charing Methodology*.

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

Not Applicable

Self-Governance Recommended: Yes / No

No

Justification for Self-Governance Recommendation

Not Applicable

Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?

It is not believed that this proposal will interact with any ongoing SCRs.

Impact on Computer Systems and Processes used by CUSC Parties:

DCLF ICRP transport model

Details of any Related Modification to Other Industry Codes

None

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

[x] (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);

[x] (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.

[X] (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).

Full justification:

The proposal would facilitate relevant objective a) by supporting effective competition in the wider European generation market through a reduction in the proportion of total TNUoS charges paid by generators.

It would also provide a more stable TNUoS charging environment for generators which would enable better planning and decision making and thereby enhance competition.

.

The proposal would also facilitate objective c) in relation to taking proper account of developments in transmission licensees' transmission businesses.

The proposal would support objective d) by reflecting the full implementation of the European internal market due in 2014 and therefore the necessity to create a more level playing field for GB generators against European competition.

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.

☐ (e) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Objective (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).

Full justification:

Not applicable.

Additional details

Details of Proposers: (Organisation Name)	Intergen
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:	Nigel Cornwall Cornwall Energy 01603 604406 nigel@cornwallenergy.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	 Robert Longden Associate of Cornwall Energy tbc rcl@longdenr.wanadoo.co.uk
Attachments (Yes/No): No **If Yes, Title and No. of pages of each Attachment:**	

Contact Us

If you have any questions or need any advice on how to fill in this form please contact the Panel Secretary:

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

For examples of recent CUSC Modifications Proposals that have been raised please visit the National Grid Website at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/Current/

Submitting the Proposal

Once you have completed this form, please return to the Panel Secretary, either by email to jade.clarke@nationalgrid.com and copied to cusc.team@nationalgrid.com, or by post to:

Jade Clarke
CUSC Modifications Panel Secretary, TNS
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

If no more information is required, we will contact you with a Modification Proposal number and the date the Proposal will be considered by the Panel. If, in the opinion of the Panel Secretary, the form fails to provide the information required in the CUSC, the Proposal can be rejected. You will be informed of the rejection and the Panel will discuss the issue at the next meeting. The Panel can reverse the Panel Secretary's decision and if this happens the Panel Secretary will inform you.

nationalgrid

Workgroup Terms of Reference and Membership
TERMS OF REFERENCE FOR CMP227 WORKGROUP

Under the current structure of the TNUoS charges, the total amount of allowed revenue to be recovered is split between generators and suppliers in the ratio of 27:73, this is referred to as the G:D split. CMP227 aims to change the G:D split, reducing the proportion of TNUoS charges paid by generators to a suggested ratio of 15:85, which corresponds with the approach modelled under Project TransmiT.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal 227 'Reduce the G:D split of TNUoS charges, for example to 15:85' tabled by Intergen at the CUSC Modifications Panel meeting on 28th February 2014.

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

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.

(d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).

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) *Assess impact on GB consumers*
   b) *Explore suitable implementation options*
   c) *Assess interaction with Electricity Market Reform (EMR), e.g. impact on capacity market*
   d) *Assess interaction with Tarification Guidelines.*
   e) *Be mindful of social welfare arguments, CMP201 'Removal of BSUoS Charges from Generators' and CMP224 'Cap on the total TNUoS target revenue to be recovered from generation users'.*

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 17th July 2014 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 25th July 2014.

Membership

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

Role	Name	Representing
Chairman	Alex Thomason	
National Grid Representative*	Tushar Singh	National Grid
Industry Representatives*	Paul Mott	EDF
	Jonathan Wisdom	Npower
	Garth Graham	SSE
	Robert Longden	Intergen
	Donald Smith	Ogfem
	Cem Suleyman	DRAX
	Guy Phillips	EON
	Lisa Waters	Eggborough Power Ltd
	Ebba John	Dong energy
	James Anderson	Scottish Power
	Frank Prashad	RWE N Power
Authority Representatives	Donald Smith	Ogfem
Technical secretary	Jade Clarke	
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 CMP227 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 1 – Indicative Workgroup Timetable

The following timetable is indicative for CMP227.

W/C 17th March 2014	Deadline for comments on Terms of Reference / nominations for Workgroup membership
3rd April 2014	Workgroup meeting 1
10th April 2014	Workgroup meeting 2
W/C 28th April 2014	Workgroup meeting 3
W/C 12th May 2014	Workgroup meeting 4
19th May 2014	Workgroup Consultation issued for 1 week Workgroup comment
27th May 2014	Deadline for comment
29th May 2014	Workgroup Consultation published
19th June 2014	Deadline for responses
W/C 30th June 2014	Workgroup meeting 5
7th July 2014	Circulate draft Workgroup Report

14th July 2014	Deadline for comment
17th July 2014	Submit final Workgroup Report to Panel
25th July 2014	Present Workgroup Report at CUSC Modifications Panel

Annex 3 – Workgroup attendance register

A – Attended; X – Absent; O – Alternate; D – Dial-in

Name	Organisation	Role	03/04/2014	08/05/2014	20/06/2014	22/10/2014	15/01/2015	20/02/15	03/03/15 Telecon	23/04/15
Alex Thomason	Code Administrator	Workgroup Chair	A	A	O	A	A	O	D	A
Jade Clarke	Code Administrator	Technical Secretary	A	A	A	A	A	A	D	X
Robert Longden	Intergen	Proposer	A	D	O	A	A	A	D	A
Tushar Singh	National Grid	Workgroup Member	A	A	O	O	O	O	O	O
Nick Pittarello	National Grid	Workgroup Member	X	X	A	A	A	A	D	A
Cem Suleyman	Drax	Workgroup Member	X	A	A	A	A	A	D	A
Ebba John	Dong Energy	Workgroup Member	X	A	A	X	X	X	X	X
Garth Graham	SSE	Workgroup Member	A	A	D	A	A	A	D	A
Guy Phillips	E.ON	Workgroup Member	A	A	A	A	A	O	D	A
James Anderson	Scottish Power	Workgroup Member	A	A	X	A	A	A	D	A
Jonathan Wisdom	NPower	Workgroup Member	A	A	X	A	A	O	D	A
George Douthwaite	Npower	Alternate for Jon Wisdom	X	X	X	X	A	A	X	D

Name	Organisation	Role	03/04/2014	08/05/2014	20/06/2014	22/10/2014	15/01/2015	20/02/15	03/03/15 Telecon	23/04/15
Paul Mott	EDF	Workgroup Member	A	D	A	A	A	O	D	O
Lisa Waters	Eggborough Power Ltd	Workgroup Member	O	O	O	O	O	O	O	O
Paul Brennan	Waters Wye Associates	Alternate for Lisa Waters	A	A	A	A	A	A	D	A
Donald Smith	Ofgem	Ofgem Representative	D	D	A	A	A	A	D	D
Tom Edwards	Cornwall Energy	Observer	X	X	X	X	X	X	X	D
Frank Prashad	RWE nPower	Workgroup Member	A	A	X	X	X	X	X	X

Notes:

- Sean McGoldrick and Emma Radley chaired the Workgroup meetings for the Code Administrator on 20th June 2014 and 20th February 2015 respectively
- Tushar Singh moved to a new role within National Grid and was replaced by Nick Pittarello as the National Grid Workgroup member from June 2014 onwards
- Lisa Waters was represented by her Alternate, Paul Brennan, throughout the Workgroup
- Frank Prashad retired from RWE during the Workgroup and was not replaced

Annex 4 – Impact of modified G:D split on 2016/17 tariffs

The table below shows forecast Zonal Half Hourly demand, Zonal Non Half Hourly demand and Generation Zonal tariffs for the year 2016/17 using the Diversity model (reflecting charging changes following Project Transmit implementation):

- The 27:73 split reflects the existing regime.
- The 18.3-91.7 split reflects a regime where the generation residual is set to zero. If this option was adopted, the split would change each year.
- The 15:85 split reflects the original proposal
- The 4.26:95.74 split would outturn an average generation transmission charge of Euro 0.5 assuming a £:Euro exchange rate of 1.26 and system demand of 319TWh in the year 2016/17
- The 2.1:97.9 split would outturn an average generation transmission charge of Euro 0.25 assuming a £:Euro exchange rate of 1.26 and system demand of 319TWh in the year 2016/17
- The 0:100 split reflects no net recovery of infrastructure costs from generation (though locational signals would remain, as shown in the Generation Zonal Tarff part of the table.

CMP227 G:D Split Tariff Modelling for 2016/17
Diversity Model

£: Euro ER
1.26

Demand Fc 16/17 TWh
319

		G:D Split	27:73	18.3:81.7	15:85	4.26:95.74	2.1:97.9	0:100
		Average Gen Tx Charge Euro/MWh	3.18	2.16	1.77	0.50	0.25	0.00
		Amount recovered from demand (£m)	2178	2436	2536	2857	2921	2984
		Amount recovered from Generation (£m)	806	548	448	127	63	0
		Demand Residual (£/kW)	39.71	44.37	46.18	51.98	53.14	54.28
		Gen Residual Charge £/kW	3.29	0.00	-1.26	-5.33	-6.15	-6.95
HH	1	Northern Scotland	15.98	20.66	22.47	28.28	29.45	30.58
Zonal Tariff	2	Southern Scotland	17.10	21.77	23.59	29.39	30.56	31.70
£/kW	3	Northern	30.44	35.12	36.93	42.74	43.91	45.04
	4	North West	36.15	40.82	42.64	48.44	49.61	50.75
Includes small	5	Yorkshire	37.04	41.72	43.53	49.34	50.51	51.64
gen tariff	6	N Wales & Mersey	38.54	43.21	45.02	50.83	52.00	53.13
	7	East Midlands	40.65	45.32	47.13	52.94	54.11	55.24
	8	Midlands	41.80	46.48	48.29	54.10	55.27	56.40
	9	Eastern	42.71	47.39	49.20	55.01	56.18	57.31
	10	South Wales	39.54	44.22	46.03	51.83	53.00	54.14
	11	South East	46.17	50.85	52.66	58.47	59.63	60.77
	12	London	48.10	52.78	54.59	60.40	61.57	62.70
	13	Southern	46.75	51.43	53.24	59.05	60.22	61.35
	14	South Western	46.07	50.75	52.56	58.37	59.54	60.67
NHH	1	Northern Scotland	2.16	2.80	3.04	3.83	3.99	4.14
Zonal Tariff	2	Southern Scotland	2.38	3.03	3.28	4.08	4.25	4.40
p/kWh	3	Northern	4.14	4.78	5.03	5.82	5.98	6.13
	4	North West	5.18	5.85	6.10	6.94	7.10	7.27
Includes small	5	Yorkshire	5.04	5.67	5.92	6.71	6.87	7.02
gen tariff	6	N Wales & Mersey	5.44	6.10	6.36	7.18	7.34	7.50
	7	East Midlands	5.63	6.28	6.53	7.33	7.49	7.65
	8	Midlands	5.87	6.52	6.78	7.59	7.75	7.91
	9	Eastern	5.86	6.50	6.75	7.55	7.71	7.86
	10	South Wales	5.22	5.84	6.08	6.85	7.00	7.15
	11	South East	6.34	6.98	7.23	8.03	8.19	8.34
	12	London	6.41	7.04	7.28	8.05	8.21	8.36
	13	Southern	6.49	7.13	7.39	8.19	8.35	8.51
	14	South Western	6.24	6.87	7.11	7.90	8.06	8.21
	1	North Scotland	35.88	32.61	31.34	27.27	26.45	25.65
Generation	2	East Aberdeenshire	31.38	28.10	26.83	22.76	21.94	21.15
Zonal Tariff	3	Western Highlands	34.44	31.17	29.90	25.83	25.01	24.21
(£/kW)	4	Skye and Lochalsh	32.00	28.72	27.45	23.38	22.56	21.77
	5	Eastern Grampian and Tayside	32.62	29.34	28.07	24.00	23.18	22.39
Actual tariff	6	Central Grampian	34.39	31.11	29.84	25.77	24.96	24.16
depends on	7	Argyll	33.67	30.40	29.13	25.06	24.24	23.44
plant type	8	The Trossachs	30.43	27.15	25.88	21.81	20.99	20.20
and load	9	Stirlingshire and Fife	29.06	25.78	24.51	20.44	19.62	18.83
factor	10	South West Scotland	31.80	28.52	27.25	23.18	22.36	21.57
	11	Lothian and Borders	23.10	19.82	18.55	14.48	13.66	12.86
	12	Solway and Cheviot	19.75	16.47	15.20	11.13	10.31	9.52
	13	North East England	13.47	10.19	8.92	4.85	4.03	3.24
	14	North Lancashire and The Lakes	10.87	7.59	6.33	2.26	1.44	0.64
	15	South Lancs, Yorkshire and Humber	8.13	4.85	3.58	-0.49	-1.31	-2.10
	16	North Midlands and North Wales	5.48	2.21	0.94	-3.13	-3.95	-4.75
	17	South Lincs and North Norfolk	4.36	1.08	-0.19	-4.25	-5.07	-5.87
	18	Mid Wales and The Midlands	3.53	0.25	-1.02	-5.09	-5.91	-6.70
	19	Anglesey and Snowdon	6.20	2.92	1.65	-2.42	-3.24	-4.04
	20	Pembrokeshire	6.50	3.22	1.95	-2.12	-2.94	-3.74
	21	South Wales	3.96	0.69	-0.58	-4.65	-5.47	-6.27
	22	Cotswold	0.73	-2.55	-3.82	-7.89	-8.70	-9.50
	23	Central London	-3.46	-6.74	-8.00	-12.07	-12.89	-13.69
	24	Essex and Kent	-0.11	-3.39	-4.66	-8.73	-9.55	-10.35
	25	Oxfordshire, Surrey and Sussex	-1.57	-4.85	-6.12	-10.19	-11.00	-11.80
	26	Somerset and Wessex	-3.64	-6.92	-8.19	-12.26	-13.07	-13.87
	27	West Devon and Cornwall	-5.30	-8.57	-9.84	-13.91	-14.73	-15.53

Annex 5 – National Grid Note on Rationale for Generation Residual Set to Zero WACM

Note on Rationale for Generation Residual Set to Zero WACM

BACKGROUND

1 At the CMP227 WG on 15th January 2015, a vote was held to agree Working Group Alternative CUSC Modifications (WACMs) to the 15:85 original.

2 At this meeting, the key argument used to justify setting the generation residual to zero was that it would prevent a negative residual charge for generation. It was the first time this argument was used for this WACM.

3 This note discusses whether the above argument is true and the implications.

GENERATION TNUOS

4 Revenue collected from generation comes from various tariffs and elements of tariffs:

(a) Offshore Local Circuit Tariffs

(b) Onshore Local Circuit

(c) Onshore Local Substation

(d) Locational element of the wider tariff

(e) Residual element of the wider tariff

5 Elements (a) to (d) are set through various methodologies but crucially are not affected/ governed by the G/D split. The EU limit means that National Grid broadly attempts to recover £600m from generation. The residual is set therefore to recover £600m less the elements (a) to (d).

6 When the sum of the elements (a) to (d) is less than £600m then the generation residual is positive. If for example these elements collected £500m the Generation residual would be set to collect £100m.

7 If the generation residual is set to zero, then £100m would have to be collected through demand charges. This can be achieved through adjusting the G/D proportions so that National Grid only collects £500m from Generation and the remainder from demand.

8 However, when the sum of the elements (a) to (d) is greater than £600m then the generation residual must be negative. If the generation residual was fixed at zero then the amount of revenue collected from Generation will go above £600m. The crucial thing to note is that the elements (a) to (d) cannot be adjusted (reduced) without further charging methodology changes. The generation residual is the only apparatus National Grid can use to adjust tariffs so that no more than £600m is collected.

IMPACT OF CMP213

9 Under CMP213 Generation revenue collected from the locational elements of the Wider tariff increases from ~£50m in 2015/16 to ~£260m in 2016/17. As well as the

methodology change brought about by CMP213, the amount of revenue collected from Offshore local charges increases over the next 5 years due to new OFTOs, and the amount of contracted generation increases year on year. The combination of these factors means that elements (a) to (d) are expected to exceed £600m around 2018/19.

10 Therefore under the current agreed methodology and EU limit positions, if the generation residual was pinned to zero National Grid would collect more than £600m and be in breach of the EU limit.

CONCLUSION

11 Setting the generation residual to zero is likely to bring the TNUoS charging methodology into conflict with the EU limit by 2018/19 and is not a sustainable change to the Code.

12 In view of the above information, the CMP227 Working Group may wish to consider whether this WACM is viable.

Annex 6 – National Grid Analysis

CMP227 Analysis

(by National Grid on behalf of the CMP227 Working Group)

ASSESSMENT OF IMPACT ON THE MARKET ASSUMING A CLOSED ECONOMY

1 Are reductions in wholesale prices and reductions in subsidy payments cumulative?

(a) The Money-Flow Model (see Appendix A) shows that a change in the G:D split can result in lower wholesale prices and capacity mechanism subsidy payments, however, they are offset by the increased demand residual paid by Suppliers. Therefore, any change to the G:D split simply reallocates money between pots with no overall winners or losers, excluding the reallocation of risk. All other things remaining equal, reductions in wholesale prices and subsidy payments arising from a change to the G:D split are not cumulative – the lower generator costs can only manifest themselves in either lower market prices **or** lower subsidy payments.

(b) The results from the model show that using current price indicators, for every percentage reduction in the G component of the G:D split, Capacity Mechanism costs fall by £17m and the market price is about £0.03p/MWh lower. However, these changes are offset by an increase of £25m in the demand residual. Total consumer costs, and generator income remain the same overall. The table below shows the results from the analysis for a number of G:D split scenarios:

Scenarios	Today	1	2	3
G %	27%	26%	15%	0
D %	73%	74%	85%	100%
G Residual £/kW	5.81	5.47	1.73	-3.36
D Residual £/kW	30.04	30.49	35.42	42.13
CM Capacity Price	19.40	19.06	15.33	10.24
CM Payments £m	956	939	755	504
Demand Residual £m	1661	1686	1958	2330
Inferred Market Price	42.03	42.00	41.73	41.35
Generator Income £m	13694	13694	13694	13694
Total Consumer Costs £m	16171	16171	16171	16171
Difference £m	0	0	0	0

(c) The table shows that regardless of the G:D split, money is simply reallocated to different pots with no overall winners or losers, excluding the reallocation of risk. Under all scenarios, reductions in Capacity Mechanism and market prices are offset by increases in the demand residual.

2 What is the impact on CfDs?

(a) The principle for CfDs is exactly the same as for the Capacity Mechanism. A lower G charge may enable a lower strike price, however any reduction is offset by the increase in the demand residual leading to no overall winners or losers.

3 How long does it take for the market to adjust to changes in TNUoS?

(a) In its Retail Market Review analysis, Ofgem suggest that TNUoS changes are passed through at the next contracting round i.e. an 18 month delay.

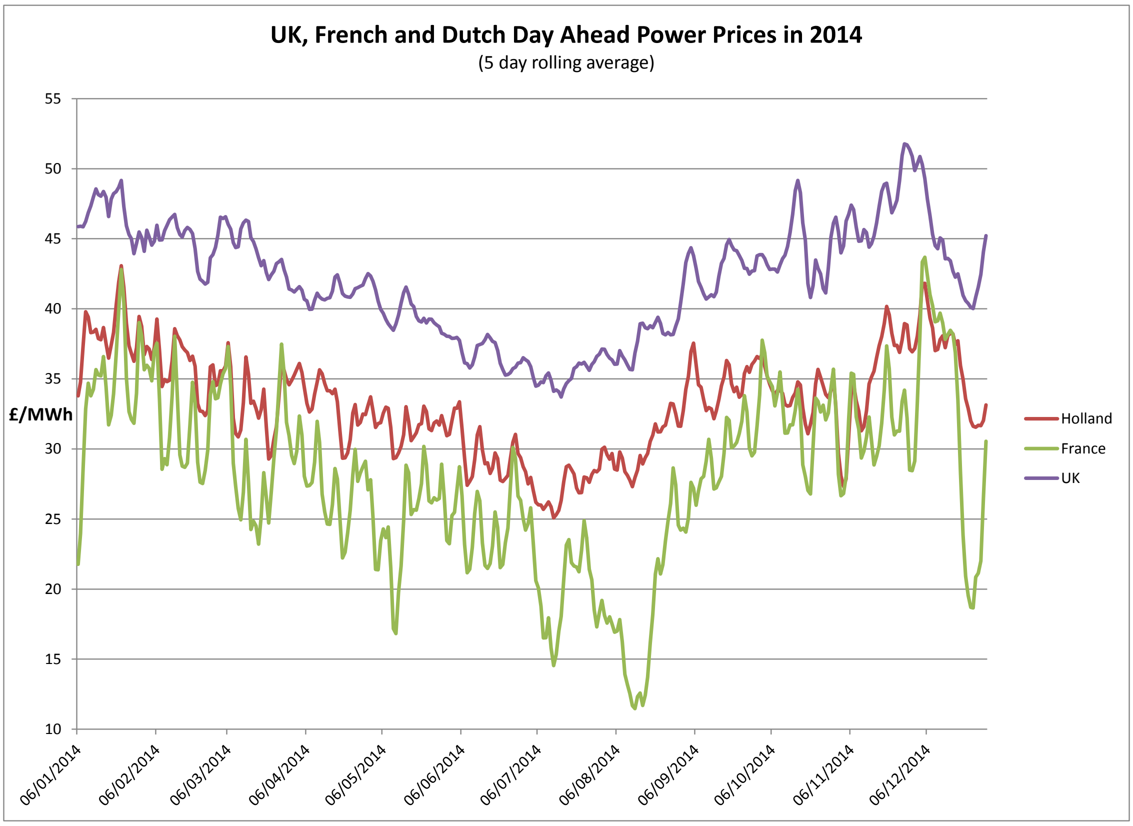
4 How would suppliers pass on charge increases to consumers?

(a) National Grid would expect that depending on the existing contractual position with their customers, Suppliers would seek to pass through increased costs immediately, or as soon as contractually possible.

TRADE

5 What is the differential required to switch interconnector flows?

(a) The graph below compares UK, French and Dutch day ahead power prices in 2014. Data is taken from APX for UK and Dutch prices, and EPEX for French prices. Daily spot GBPEUR exchange rate has been applied.



(b) Average price in the UK was £42.03/MWh compared to £27.96/MWh in France and £33.22/MWh in the Netherlands. The average differential is therefore £14.41MWh to France and £8.81/MWh to the Netherlands.

(c) The lowest day-ahead price differential between the UK and continental Europe in 2014 was £0.61/MWh and therefore it is highly likely that any reverse interconnector flows were as a consequence of SO-SO actions.

6 Assuming 100% TNUoS transfer to wholesale price, how often would flows be affected?

(a) In an open economy (with interconnectors) and all other things remaining equal, UK generators would be receiving a reduction in cost base relative to European generators. As the working group has discussed at great length, it is arguable whether reducing the G charge would be a levelling of the playing field or the introduction of a new distortion – given that transmission tariffs are only one feature of the "whole" electricity regime in any given member state (GB's Capacity Mechanism and Carbon Price Support mechanism are excellent examples of potential distortions versus European generation). Based on 2014 prices, it would have to believed that altering the G:D split would advantage UK generators to the degree that enables them to reduce wholesale prices in the order of £15/MWh to France and £9/MWh to the Netherlands for any substantive change in interconnector flow direction.

(b) The table below captures results from modelling reduced market prices if the reduction in G is passed through 100%, all other things remaining equal.

Scenarios	Today	1	2	3
G %	27%	26%	15%	0
D %	73%	74%	85%	100%
G Residual £/kW	5.81	5.47	1.73	-3.36
D Residual £/kW	30.04	30.49	35.42	42.13
CM Capacity Price	19.40	19.40	19.40	19.40
CM Payments £m	956	956	956	956
Demand Residual £m	1661	1686	1958	2330
Inferred Market Price	42.03	41.95	41.10	39.93
Generator Income £m	13694	13694	13694	13694
Total Consumer Costs £m	16171	16171	16171	16171
Difference £m	0	-1	-1	0

(c) The table shows that even in the 0/100 scenario, market price could fall by just over £2.10/MWh, however, given the existing gap between GB and continental market price differentials, it is unlikely that any change to the G:D split would have any material effect on interconnector flows in the short to medium term.

(d) If day ahead GB energy prices were £2.10/MWh lower in 2014, day ahead energy prices would be higher in GB compared to continental Europe on 5 days. Costs have not been added to account for interconnector capacity, and no adjustment has been made for the feedback loop that would be expected to increase the GB wholesale price from the change in the supply:demand balance i.e. higher demand in GB.

(e) The Carbon Price Support[1] mechanism (the UK-only element of the Carbon Floor Price designed to encourage investment in non-carbon emitting generation) capped at £18 per tonne of CO_2 until 2019-20, is likely to ensure a continued differential between UK and continental European energy prices for at least this period.

RISK

7 What is the predictability of TNUoS charges?

(a) TNUoS predictability is affected by changes in TSO revenues and tariffs are affected by changes in demand and generation. The tables below show the

[1] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/293849/TIIN_6002_7047_carbon_price_floor_and_other_technical_amendments.pdf

degree of change in the generation charging base and how demand forecast error affects allowed revenues.

	Generation Charging Base			
Charging Year	Contracted TEC t-14m[2]	Final View[3] t-2m	Diff (GW)	%
2008/2009	84.8	74.5	-10	-12%
2009/2010	86.5	79.3	-7	-8%
2010/2011	89.2	84.8	-4	-5%
2011/2012	91.1	83.2	-8	-9%
2012/2013	93.4	83.3	-10	-11%
2013/2014	80.6	75.0	-6	-7%
2014/2015	81.3	73.0	-8	-10%

(b) The generation charging base is arguably easier to model than demand because it is contracted. The t-2 Final View is reasonably accurate because notification of TEC reduction is the only uncertainty as it is unlikely for new generation to appear at short notice. In addition the ~£600m G charge (based on the €2.5/MWh cap) is increasingly being taken up by offshore locational charges, and so the variation to the residual arising from notification of TEC changes is likely to have lower impact to tariffs over time.

[2] Contracted TEC (i.e. may not be National Grid "best view", but is a transparent snapshot at a particular moment in time used in the 5 year forecast).

[3] Used in TNUoS tariff setting

(c) For demand, the difference between forecast and actual can be affected by many factors including the weather (in forecasting timescales, weather-normal scenarios are assumed, but any given year will have its own specific weather conditions), customer efficiencies, embedded generation penetration, the degree of TRIAD avoidance, and customer price elasticity.

(d) Data on NHH and HH demand forecasting error and the impact on over/ under recoveries is shown below:

Impact of demand forecast error on allowed revenue recovery

	2009/10	2010/11	2011/12	2012/13	2013/14
Total Allowed Revenue (£m)	£ 1,428	£ 1,600	£ 1,724	£ 1,949	£ 2,153
73% from demand (£m)	£ 1,043	£ 1,168	£ 1,259	£ 1,423	£ 1,572

Forecasts (@ max t-14m)	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**
HH Demand (MWh)	16,459	16,000	16,100	16,100	16,100
Revenue Recovery HH (£m)	**£ 332**	**£ 346**	**£ 369**	**£ 420**	**£ 464**
NHH (TWh)	29.5	28.9	29.1	28.45	28.6
Revenue Recovery NHH (£m)	**£ 711**	**£ 822**	**£ 890**	**£ 1,002**	**£ 1,108**

Actuals	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**
HH Demand (MWh)	16,200	16257	15226	15960	14810
Revenue Recovery HH (£m)	**£ 326**	**£ 341**	**£ 352**	**£ 416**	**£ 430**
NHH (TWh)	29.211	29.187	27.96	29.033	27.612
Revenue Recovery NHH (£m)	**£ 707**	**£ 807**	**£ 860**	**£ 1,029**	**£ 1,077**

Demand Forecast Error	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**
HH Demand difference (MWh)	259	-257	874	140	1,290
HH % error	1.6%	-1.6%	5.7%	0.9%	8.7%
NHH Demand dfference (MWh)	289	-287	1140	-583	988
NHH% error	1.0%	-1.0%	4.1%	-2.0%	3.6%

Revenue Impact (£m)	**2009/10**	**2010/11**	**2011/12**	**2012/13**	**2013/14**
£m HH difference	6	5	17	5	34
£m HH Forecast Error	1.9%	1.5%	4.8%	1.2%	8.0%
£m NHH difference	4	14	30	-27	31
£m NHH Forecast Error	0.5%	1.8%	3.4%	-2.6%	2.8%

Total Over/ Under Recovery from demand forecast error £m	**10**	**20**	**46**	**-22**	**65**

(e) The table above shows the impact on TO allowed revenue over/under-recoveries resulting from demand forecast error. 2013/14 was an exceptionally mild winter accounting for the large HH forecast error. Increasing the demand residual from a change in the G:D split will increase the size of over/ under recoveries arising from demand forecast error.

8 What impact will CMP224 have on predictability of tariffs?

(a) EU Regulation 838/2010 caps annual average generator charges to €2.5/MWh and CUSC Modification Proposal CMP224 caps this number to €2.34/MWh to incorporate a risk margin for forecasting error. The amount of money to be recovered from generation is calculated as €2.34/MWh multiplied by total system energy demand (TWh) and divided by the exchange rate. The cap also includes energy charges.

(b) CMP224 therefore creates the potential for the G:D split to be set annually. Indeed the cap is biting for 2015/16 tariffs where the G:D split is to be set at 23.1%:76.9%. CMP224 therefore reduces the absolute predictability of tariffs, but sets a limit on what generation will pay, and therefore when the cap bites (and it is expected to continue to do so), generation has some certainty on final outlay. When the cap doesn't bite, any uncertainty is no different to today.

(c) There are discussions ongoing within the EU presently to remove the €2.5/MWh cap, however no such directive has yet been implemented and the cap is expected to remain for the foreseeable future.

9 How does this proposal change the allocation of risk between suppliers, generators and consumers?

(a) National Grid does not believe changes in the G:D split have a significant impact on the risk management of tariff volatility. The main reservation is that as the G:D split is purely an arbitrary number, any change to another arbitrary number potentially opens the door to further debates on the appropriateness of other arbitrary numbers. This in itself has the potential to create uncertainty.

(b) Demand is more difficult to forecast than generation, therefore it is expected that a higher demand residual will lead to larger over/under recoveries of TO allowed revenue resulting from demand forecast error.

(c) Separately, as outlined in Section 3 Part III of the CUSC, National Grid only secures TNUoS demand charges. Therefore the Security Requirement for Suppliers will increase as a result of changes to the G:D split. Combined with the effect in paragraph 9(b), this is unlikely to benefit GB consumers.

(d)

Appendix A

Money Flow Model

10 The Money Flow Model maps at a high level how money moves in the electricity industry between consumers, suppliers, generators, and National Grid, and the impact that changes to the G:D split has on market and capacity mechanism bid prices. The model compares those money flows under different G:D splits; 27/73 (today), 15/85 and 0/100.

ASSUMPTIONS

11 For the purposes of the modelling, the market is assumed to be in equilibrium and therefore rent earned by generators today remains the same. This is true as changes to the G:D split do not pass on a competitive advantage to any specific GB generator. Further, it is also assumed that all plant receive capacity mechanism (or CfD) payments, which for the purposes of this modelling, it is a reasonable assumption that generation volumes remain the same.

12 In the model, reductions in G are primarily passed on through lower capacity market bids, and changes in market price are used as a "balancing factor" to meet the assumption in the paragraph above.

DATA

13 Data used for the "today" starting scenario:

(a) Transmission tariffs for 2014/15 including the assumptions used in their derivation i.e. generation charging base of 73GW and demand charging base of 55.3GW

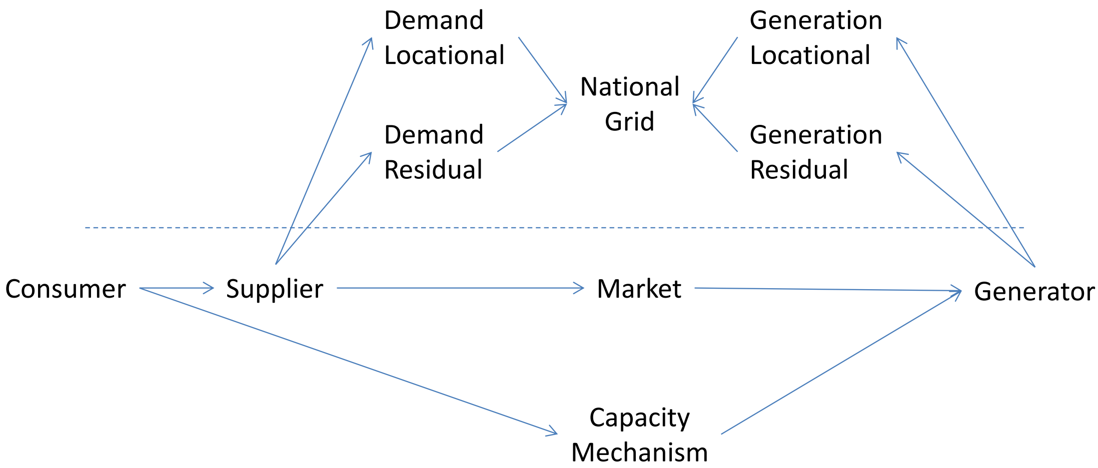
(b) System energy for the year 2014/15 is assumed to be 319TWh

(c) UK Market price is £42.03/MWh (Source: APX) for 2014

(d) Capacity Mechanism clearing price and size is as reported from the December 2014 auction result as 49.26GW at £19.40/kW.

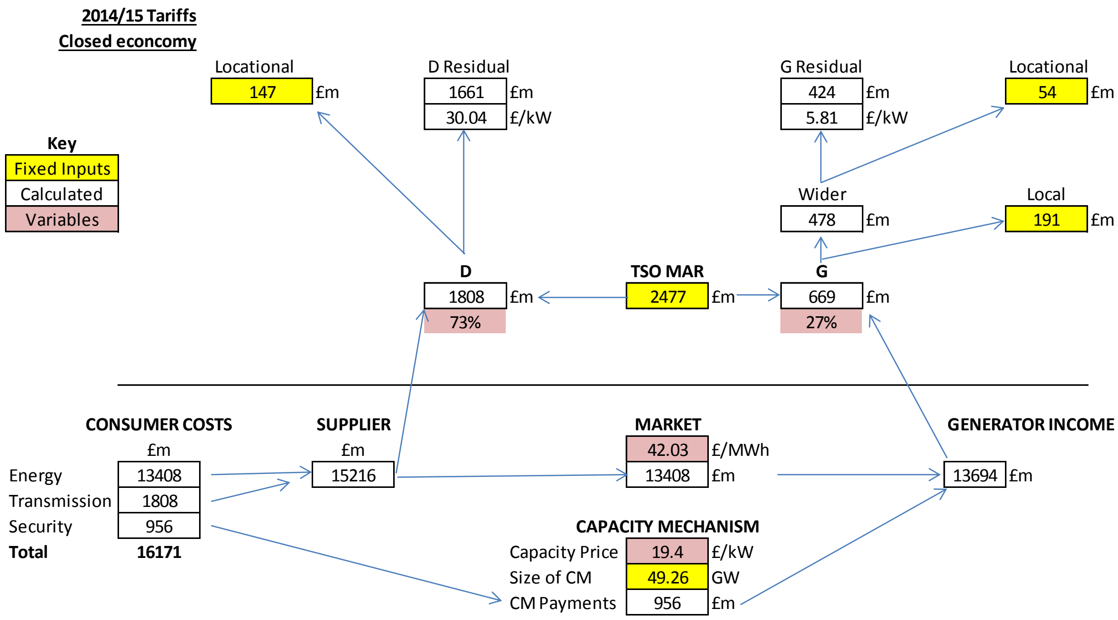
THE MODEL

14 An high level simplistic map of money flows is used as the basis to show how changes in the G:D split alter overall revenues in the value chain, with National Grid money flows above the dotted line and industry money flows below the dotted line, as shown in the diagram:



15 Consumers pay Suppliers and contribute to subsidy mechanisms such as the Capacity Mechanism (modelled here, but the principle also applies to Contract for Difference strike prices). Suppliers procure energy from the market and pay National Grid transmission charges which are either fixed (locational demand charges) or vary with the G:D split (demand residual). Both the market and capacity mechanism revenues finance Generators. Generators also make a contribution to National Grid's transmission charges which are either fixed (locational generation charges) or vary with the G:D split (generation residual).

16 Injecting the appropriate numbers using the data described above, we can model industry money flows as they exist today with a 27/37 G:D split:



17 Using the relevant data, we can see that total consumer costs amount to about £16bn shared between National Grid's allowed revenue of £2.5bn and net generator income (after the G contribution to National Grid) amounting to £13.5bn.

18 The variables shaded pink can then be altered to reflect alternative scenarios. For a 15:85 G:D split, the percentage values are changed accordingly. The new split has the effect of lowering the generation residual and increasing the demand residual. The

capacity price is reduced by the difference between the generation residual in the 27/73 scenario and the new generation residual in the 15/85 scenario. The new market price is then inferred to match the generator income in the original 27/73 scenario. The same was repeated for the 0/100 scenario.

Annex 7 - Customer benefits supporting paper prepared by Cornwall Energy

cornwallenergy

Strategic energy market intelligence

Date: August 2014

CMP 227 – Customer benefits

A supporting paper prepared for Intergen

Prepared by Cornwall Energy

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Strategic energy market intelligence

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CMP 227 working group		09/07/2014	2

Contents

1 Executive summary

- CMP 227 seeks to alter the Generator: Demand (G:D) split for the recovery of Transmission Network Use of System (TNUoS) charges. It proposes the ratio is changed from the current 27:73 (G:D) split to one that charges a lower level of charges to generation, to bring Great Britain transmission charges more closely in line with generators in other European countries.
- The proposers preferred approach is to charge generators purely on the basis of the locational charge calculated by National Grid's ICRP model. There would be no residual charge allocated to generators.
- Another current CUSC proposal, CMP201 *Removal of BSUoS Charges from Generators,* proposes to remove balancing services use of system (BSUoS) charges from generators with similar aims to CMP227. Ofgem previously said it is minded to reject this proposal (a decision is due this summer) primarily on the grounds that lower costs would lead to increased demand for GB generation and so raise the cost of wholesale power to GB consumers. Working Group members have suggested these arguments are similarly applicable to CMP227.
- We argue, however, that the regulator's minded-to position to reject CMP201 is based on an incomplete view of the arguments, as the extra cost to consumers from increased exports does not take into account a number of important counter-balancing reductions in consumer spending on generator subsidy schemes, and also benefits arising from increase in system security.
- We also argue that CMP227 (and by implication CMP201) should also enable more levelised access to interconnectors helping to better realise claimed benefits under separate initiatives.
- By reducing the burden of TNUoS charges on generators and removing a distortion to costs not seen in other markets, CMP227 would encourage more effective competition with European generators. This would have positive, not negative effects:
    - increased demand benefits security of supply by ensuring that GB gas plant (that are currently struggling with low spark spreads) see lower costs helping keep plant on the system longer;
    - reducing the cost of subsidy mechanisms by allowing plant to place smaller bids into the Capacity Mechanism. It is estimated that CMP227 (based on the June 2014 Capacity Market Impact Assessment) could reduce the cost of the capacity mechanism to consumers by at least between £210mn to £243mn;
    - in addition reducing network costs to generators should also result in lower strike prices being needed by renewables generators under the Contract for Difference Feed-in Tariffs (CfD FiTs), further reducing costs to consumers;
    - CMP227 aligns the GB market with the European Target Model, which will help to harmonise markets and encourage greater interconnection;
    - by reducing overall costs to generators, it reduces the year-on-year charge volatility seen (and expected in coming years) in TNUoS charges and places the risks where they can best be managed on suppliers, who can recover these costs from consumers; and
    - we estimate possible consumer benefits of CMP227 of between £47mn and £376mn in 2018-19.
- ACER has recommended that after December 2014 capacity-based charges should not be subject to the current €2.50/MWh cap set out in 838/2010 as they can provide efficient locational signals to generators but also argued that, as far as possible, charges should be harmonised. Regardless of the final decision by the European Commission, CMP277 would better align charges with neighbouring markets and so promote cross border trade and security of supply.
- Assuming the solution reflects locational charges (and not residual charges), the proposed solution would be demonstrably cost-reflective and therefore compliant with the ACER guidelines.

2 CMP227 introduction

CMP227 seeks to change the G:D split for levying TNUoS charges. Under the current structure of TNUoS charges the total amount of allowed revenue to be recovered is split between generators and suppliers (demand) in a ratio of 27:73.

The proposal would change the split to a lower generator share, suggested at that time to be 15:85, almost halving the proportion paid by generators. This change was first mooted during the development of work undertaken for Project Transmit, and received significant stakeholder support.

A key rationale for implementing the proposed change is to level the playing field with generators in other European countries. This would facilitate competition in generation in the wider European market through improved harmonisation of the regulated costs faced by generators in different countries.

3 CMP201

On 8 November 2013 Ofgem released its minded-to position on another modification proposal which sought to remove costs from generators.

CMP201 *Removal of BSUoS Charges from Generators* was raised by NGET in December 2011. It seeks to remove BSUoS charges from generation, so that the full charge is applied to demand only. Currently the charge is shared equally between suppliers and generators on a uniform per MWh basis.

NGET argued that the change would align GB market arrangements with other EU member states where equivalent charges are generally levied on demand. The change could therefore help deliver more effective competition and trade across the EU. National Grid stated the proposal should have no impact on consumers as cost is passed through regardless of where it is charged to. A chronology of the proposals development can be seen below.

3.1 CMP201 timeline

- 8 December 2011—CMP201 was raised at the Connection and Use of System Code (CUSC) Panel which set up a workgroup to consider the proposal. Two rounds of industry consultation followed with a Panel discussion on 28 September 2012;
- 10 October 2012—the CUSC Panel submitted a Final Modification Report (FMR) on the proposal to Ofgem. The Panel voted to recommend the implementation of the original proposal, which proposed a 1 April 2016 implementation date;
- 25 October 2012—Ofgem sent back the report to the CUSC Panel stating the analysis was "incomplete" and needed more attention on long-term quantitative impacts to consumers;
- October 2012 to April 2013—the workgroup reconvened to address the issues raised, and consulted again;
- 9 May 2013—following consideration by the CUSC Panel on 26 April 2013, the revised FMR was submitted to the Authority. Again the CUSC Panel recommended implementation of the proposal;
- 8 November 2013—the regulator issued its impact assessment consultation, indicating it was "minded to reject" the proposal; and
- 16 January 2014—consultation closed on Ofgem's impact assessment. A decision is expected in "summer 2014". In the May 2013 CUSC modification report it was suggested the original proposal would be implementable within 24 months of an Authority decision.

3.2 Ofgem's CMP201 impact assessment

Despite its minded-to position to reject the proposal, Ofgem did agree that, when considered in isolation, removing BSUoS should promote more efficient trade between GB and European interconnected markets, as GB prices would become more cost competitive with their European counterparts. The Authority added that it is "fully committed" to an integrated European electricity market and harmonising of prices could be helped by the removal of BSUoS for GB generation.

Ofgem subsequently assessed the proposal against three relevant objectives.

3.2.1 Competition

The proposal, according to Ofgem, could improve trade efficiencies with the European market as removing BSUoS costs should help interconnector flows reflect the true differences in generation costs. Competition should increase, with parties able to trade on an equal basis, with higher profit margins likely for GB generators. This should in turn attract additional investment, increasing market entry and reducing the risk of plant closure. The regulator stated the proposal should therefore "increase effective competition in generation". It was only in deeper analysis that Ofgem thought "existing market distortions" would impair this competition.

3.2.2 Cost reflectivity

Ofgem saw CMP201 as neutral against this objective.

3.2.3 Policy developments

The regulator considered CMP201 would help progress the European Directive Third Package by increasing European interconnection among domestic markets, stating its initial view was that CMP201 "marginally better facilitates the development of the transmission businesses across Europe". The Authority also thought the proposal may marginally benefit security of supply, with more investment potentially attracted to GB through competitive wholesale prices.

3.2.4 Ofgem concerns

Despite the proposal scoring well in terms of competition, cost reflectivity and increased connections with Europe, the benefits of the scheme would not be achieved according to Ofgem, due to "existing market distortions" that would add a cost burden to consumers.

These distortions were not outlined in National Grid's modelling process but included:

- the fact that interconnectors often flowed against the market price, with previous analysis showing this occurred up to 32% of the time. However, against this it can be argued this is now less likely to occur after the implementation of the North West Europe market coupling solution across regional markets using a common trading algorithm; and
- the range of trade-distorting tariffs and levies in the GB and Europe, including the GB Carbon Price Support (CPS), Spain's 7% levy on conventional and renewable generation, and the Netherland's tax on certain generators.

3.2.5 How would the proposal add costs to the consumer?

The Authority was also concerned that increased costs could be charged to consumers in the short-term and possibly long-term. Although the decreased costs for generators should result in lower GB wholesale prices, gross demand for GB power would increase as prices should be more competitive with Europe and hence being demanded more on the continent through interconnection. An increase in gross GB demand would cause more expensive marginal plant to come online, increasing wholesale prices.

As a result, despite GB consumers seeing no change from different BSUoS split arrangements, they would be negatively affected by the impacts noted above. National Grid modelling showed that the net cost to consumers would be in the region of £200mn to £250mn (or a 1% increase in costs), and Ofgem said this would add an estimated increase of £2 - £2.5 on the average annual domestic bill.

Although National Grid factored this short-term cost into their modelling, long-term projections by the company indicated that 500MW to 1,000MW of new capacity would offset these costs further into the future, with a competitive wholesale market creating a good investment environment. Ofgem however said that this assumption lacked quantitative evidence, with only short-term impacts being modelled by National Grid. But without the offsetting impact of new generation, the regulator stated that increases to consumer bills would continue to rise by £2 annually in the long run.

Ofgem said it also regarded National Grid's modelling as too static, with little acknowledgement of external factors. The Authority noted that government policies, market arrangements on both sides of interconnectors, and investor sentiment all influenced long-term investment decisions as well as costs, and were not considered by National Grid.

3.3 Ofgem's minded-to position

The regulator's minded-to position to reject the proposal came down to three key factors:

3.3.1 Costs to consumers

Ofgem considered the cost effects of the proposal, both the short-term rise in cost due to higher gross demand and long-term effects with insufficient new capacity, created a greater cost burden for the consumer. This supported its view that consumers would pay more in the long-run for this policy.

3.3.2 European Integration and existing market distortions

The regulator also assessed the proposal against European market integration, concluding that, while on a "standalone" basis the proposal could increase integration, it had not been raised in the context of a "holistic appraisal" of issues impacting efficient trade between EU member states.

Notably the existing market distortions of levies, taxes and variable demand had not been factored into models by National Grid:

- National Grid's model only considered two years; 2010-11 and 2011-12. GB generation costs are forecast to increase as a result of reduced capacity and increased costs under the CPS. The costs increases would outweigh the decreased cost of BSUoS and mitigate the increased demand for GB power; and
- Ofgem objected to National Grid's assertion that 500MW to 1,000MW of new investment would come online following an increase in competitiveness in the GB generation mix.

3.3.3 The inefficient interconnector market

National Grid's proposal modelled a perfectly competitive interconnector market, where capacity was available at all times, was the same in both directions and could be used at no cost. National Grid's FMR acknowledged previous analysis that stated electricity could flow through interconnectors against market price up to 32% of the time.

However Ofgem considered this "market distortion" undermined a key principle of the decision, in which GB electricity flowed to the continent as a result of lower BSUoS charges.

4 Benefits case for CMP227

4.1 Applicable objectives

The key benefits of the proposal are considered in this section and focus on its positive impact on security of supply, the reduced costs of subsidy mechanisms to consumers, and alignment with Europe's Target Model.

In its determination Ofgem will assess the proposal against applicable CUSC objectives (see below), as well as against its wider statutory duties, which include security of supply, furthering competition, consumer bill impacts and European integration.

The applicable objectives for charging modification changes under the CUSC as set out in Standard Licence Condition C10 of the Transmission Licence[1] are:

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

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

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

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

Intergen, the proposer, has set out some initial comments against the applicable objectives on the modification proposal form. In the following section we set out some additional factors that should be taken into account during the assessment of the modification.

4.2 Increased Security of Supply

In its *Electricity Capacity Assessment Report 2013*[2] Ofgem noted the outlook for security of supply has deteriorated; the de-rated capacity margin is expected to fall to around 4% by 2015-16, as a result of poor conditions for gas-fired generators causing plant to be taken off the market. This reduced capacity margin is expected to increase the loss of load expectation from one hour per year in 2013-14 to three hours per year in 2015-16.

Reducing the costs for generators in GB would help create a more level playing field with generators in Europe. As Ofgem notes this should push the price of GB wholesale power down making exports through the interconnector more attractive and increasing demand for GB power. This should ensure more conventional generation, which operates without subsidy, remains online or returns from mothballing to meet higher demand, thereby increasing security of supply.[3]

In 2012 the UK mothballed or closed around 6GW of gas fired capacity as a result of deteriorating conditions for the technology in the market. These plants represent sunk assets, so increasing demand to

[1] https://epr.ofgem.gov.uk/Content/Documents/Electricity%20transmission%20full%20set%20of%20consolidated%20standard%20licence%20conditions%20-%20Current%20Version.pdf

[2] https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013.pdf

[3] Centrica has recently put Langage, an 885MW station commissioned in 2010, on the market because it is unable to cover its operating costs given current commodity prices.

encourage the return of these stations is an efficient use of the resources and contributes to security of supply.

To highlight the conditions faced by current-gas fired generators, we have included a summary of spark spreads, in **Table 1**, for a notional 800MW CCGT with 50% efficiency in TNUoS charging zone 15, operating at a 50% load factor (mid merit). Gas and power prices were taken from the ICE index on 17 June 2014, Carbon prices were based on the Carbon Price Support rates for a CCGT emitting 0.41/t Co2 for every 1 MWh and BSUoS costs were based on Cornwall Energy's estimates. The plant is only expected to make a profit in two of the future seasons, when capacity margins are tightest. Overall the plant makes a loss of £29mn over the period before the Capacity Market is introduced. The reduction in TNUoS for this example station, based on an illustrative 15:85 split, reduces the loss faced by the station over the period to £8.8mn.

Table 1 Example 50% efficient CCGT spark spreads

Season	Baseload power (£/MWh)	Gas £/MWh	Carbon (£/MWh)	BSUoS (£/MWh)	TNUoS (£/MWh zone 15, baseload)	Estimated CMP 227 BSUoS (£/MWh)	Variable costs (£/MWh)	Clean Spark Spread (£/MWh)	CMP 227 Clean Spark Spread
Win-14 15	49.39	41.26	3.50	1.60	1.74	0.81	1.53	-1.98	0.69
Sum-15	49.40	37.71	6.68	1.72	1.65	0.69	1.53	-0.71	1.06
Win-15 16	54.85	43.34	6.68	1.72	1.65	0.69	1.53	-1.01	0.88
Sum-16	50.60	38.98	8.93	1.62	1.58	0.54	1.53	-2.04	-1.00
Win-16 17	55.55	43.94	8.93	1.62	1.58	0.54	1.53	-2.05	-1.01
Sum-17	50.30	39.14	8.99	1.72	1.57	0.53	1.53	-2.65	-1.61
Win-17 18	55.32	43.37	8.99	1.72	1.57	0.53	1.53	-1.86	-0.82
Sum-18	49.24	38.97	9.11	2.72	1.21	0.14	1.53	-4.29	-3.23

CMP277 addresses TNUoS costs, which are fixed costs and therefore directly attributable to the decision of a generator to remain open or not. In this respect they vary from BSUoS costs which are charged on a per MWh basis. As such, the level of TNUoS charges faced by generators has a more direct relationship to security of supply.

In addition, CMP227 would improve the predictability of TNUoS charges which at a zonal level have proved very difficult to predict over recent years, with individual generators seeing significant changes in the charges they are asked to pay year-on-year. High, increasing and unpredictable costs create significant and unnecessary risks to the ability of generators to plan, and this uncertain environment is not conducive to encouraging investment or encouraging existing generators that are under pressure to stay on the system.

CMP277 would address this issue by reducing the total TNUoS paid by generators as a class, so significantly reducing its impact. A more predictable charging background would also help facilitate investment and therefore competition.

Furthermore the proposal would lead to a more appropriate allocation of risk. Under CMP227 suppliers would bear an increased proportion of the TNUoS costs. This would be appropriate: suppliers are less exposed to changes to locational charges: as demand zones cover larger and different areas to the generation zones. Suppliers are also exposed to a higher proportion of their charge made up by the residual charge, and under our proposal would face all of it. Changes therefore tend to be smoothed out when compared to generation changes. By contrast generators are at the mercy of network, generator and demand changes that take place around them which can significantly impact their costs. Therefore the proposal should result in an overall increase in certainty of charges across generation and supply.

Overall then, in terms of the CUSC applicable objectives, reducing the costs of operating to GB generators though CMP227 would facilitate effective competition which would support security of supply through increasing generator profitability and encouraging investment. It would also enhance competition by providing a more stable TNUoS charging environment for generators, enabling better planning and decision making.

There would also be ancillary benefits in terms of system efficiency through achievement of higher load factors, especially by controllable plant.

4.3 Reduced cost of subsidy mechanisms - Capacity

Reducing the cost burden on generators will have a positive effect on consumers outside of the wholesale price of electricity.

Generators will be competing for capacity payments under the government's Capacity Market, which will see eligible technologies receive a flat £/kW payment each year in return for being able to provide capacity during periods of system stress.

The costs associated with this scheme have been modelled by DECC[4] using the Cost of New Entry (CONE) of OCGTs and CCGTs. DECC estimated in the first year of the scheme that a capacity auction cleared price of £16/kW would cost consumers £900mn in 2012 prices.

The Capacity Market rules now state generators can bid their losses between the first auction and the first payment date into their Capacity Market bid, therefore there is an even greater capacity for consumer savings as a result of CMP227.

If changing the generation and demand split to say a 15:85 resulted in a roughly £4.4/kW average decrease in generator TNUoS (and assuming this saving was passed on into the prices bid in by capacity providers), it could result in savings to consumers of between £210 and £243mn a year. This is nearly the same amount as the assessed extra cost of removing BSUoS in CMP201 to consumers; £250mn. Details of the savings are illustrated in **Table 2**; which also lists the capacity prices, and total capacity payments from the DECC Capacity Market impact assessment. The table also shows what the cost of the Capacity Market would be if the reduction in TNUoS tariffs from CMP227 was taken into account in the bids of capacity providers and the savings that might accrue to consumers as a result.

The June 2014 Impact Assessment was used in this analysis as this provides a capacity auction clearing price forecast for each year alongside a total cost for the scheme in each year, allowing reductions in total costs to be calculated. The June 2014 Impact Assessment only provides a forecast clearing prices for the auction over the length of the scheme, not the total cost. Once the necessary information is available, we will update this analysis. In the latest analysis from DECC, it is clear that the Capacity Market is likely to clear involving a higher amount of capacity than we previously assumed and the clearing price is likely to be set by new build. We believe that the auction is therefore likely to be much more sensitive to competition from conventional generation and that our assessment of the consumer benefit is likely to have been understated.

In the shorter-term there could also be savings from National Grid's supplemental balancing services, the Demand Side Balancing Reserve (DSBR) and the Supplemental Balancing Reserve (SBR), s a result of CMP227. The DSBR in particular will involve paying generators that would have closed or mothballed to be on standby over the winter of 2015-16 and 2016-17 as a backstop against tight system margins. However, if costs were reduced for these generators they might be able to remain online without subsidy.

In its final proposals[5] for the DSBR and SBR services, National Grid estimated the cost of SBR over a year could be £25/kW/year. If 2GW of CCGT plant were mothballed or withdrew from the market it could cost consumers £50mn to procure enough replacement capacity to meet security of supply targets under

[4] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324430/Final_Capacity_Market_Impact_Assessment.pdf

[5] http://www.nationalgrid.com/NR/rdonlyres/F3F35BA1-8FCA-4206-9234-85D59B2ADB66/62904/FinalProposalsConsultationDSBRSBR10thOctober2013Final1.pdf

the SBR scheme. If this capacity was procured instead through DSBR, which the system operator estimated would cost £10/kW/year with an utilisation fee of £5/kWh (assuming four hours of use a year), it would also cost £50mn. As a result of keeping generators on the system longer CMP227 could save consumers up to £50mn from avoided subsidy costs in either SBR or DSBR payments.

Table 2 Modelled costs of the Capacity Market under CMP227 (June 20 data)

(2012 prices)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capacity prices (£/kW)	39	21	18	36	29	37	35	33	35	36	36	35
Capacity Payments (£)	2079	1100	900	1714	1387	1659	1806	1650	1806	1986	1920	1867
Estimated size of CM (GW)	53	52	50	48	48	45	52	50	52	55	53	53
CMP 227 Capacity price (£/kW)	35	17	14	32	25	33	31	29	31	32	32	31
CMP 227 Capacity Payments (£mn)	1844	869	679	1504	1176	1461	1579	1429	1579	1743	1685	1631
CMP 227 CM saving (£mn)	235	231	221	210	211	198	228	221	228	243	235	235

In terms of applicable CUSC objectives CMP227 clearly facilitates objective c) in terms of reflecting developments in the transmission licensee's business though reducing the cost of balancing services and capacity support mechanisms.

4.4 Reduced cost of subsidy mechanisms – Low carbon

Government has had to factor in the cost of network connections into the strike price offered to renewables generators under the CfD FiT scheme, which will ensure a stable price for the electricity produced from low-carbon sources.

The cost of the scheme to consumers will come from topping generators up from the reference price (for intermittent generation the day-ahead market price) to the strike price; as a result higher strike prices will mean projects cost more and the government will be able to procure less low-carbon capacity given the realities of a finite budget[6].

Reducing network charges to generators will allow them to put lower strike price bids into the contract auctions, which would allow the government to procure more low-carbon capacity, more cost effectively, given the fixed budget available under the Levy Control Framework.

At this stage we have not been able to quantify these benefits.

4.5 Benefits of more efficient interconnector usage

In March 2014 National Grid published analysis[7] showing a doubling in its interconnector capacity in 2020 could unlock £1bn in benefits to consumers and that if the UK failed to bring interconnector capacity to the 10% proposed by the EU then the UK would be missing out on a price reduction of nearly £3mn every day.[8]

However, the benefits of increased interconnection may not be realised as anticipated if the way network charges are allocated create distortions in the electricity generation market and artificially inflate UK prices.

[6] The total costs available are capped under the Levy Control Framework.

[7] http://www2.nationalgrid.com/Media/UK-Press-releases/2014/%C2%A31-billion-could-be-saved-from-electricity-costs-if-UK-doubles-its-interconnector-capacity-by-2020,-says-new-analysis-from-National-Grid/

[8] There is an interaction here with the Capaicty Market as it is the government's stated intention to include interconnected capacity from the year 2 auction. With current TNUoS charging based on an artificially high cost split that is not cost reflective to generators will distort competition for availability payments and increase payments overall.

The CMP227 proposal will mitigate distortions between the GB market and interconnected European markets leading to more efficient use of interconnection assets, allowing interconnectors to flow between markets based on comparable prices and helping to increase system security and reduce wholesale power prices.

4.6 Aligning with the Single Target Model

GB practice on transmission charging is out of line with our European neighbours where the majority of European countries do not levy use of system charges to generators and, where they do, all except Ireland and Romania are at a lower level. Latest data from ENTSO-E suggests these differentials are increasing.

The direct consequence of CMP227 levelling the commercial landscape across Europe would be to facilitate competition in generation in the wider European market through improved harmonisation of the regulated costs faced by generators in different countries. It would also be a supportive and necessary move given the growing momentum towards implementing the internal energy market.

4.6.1 ACER recommendation to European Commission Regulation 838/2010 (Tariffication Guidelines)

Regulation 838/2010 includes Tariffication guidelines which sets out a range of €0 – €2.5/MWh within which average annual generator transmission use of system charges must lie. National Grid identified in forecast charges for the coming five years that this level could be exceeded, if the limit remained unchanged and as such brought forward CMP224 to allow for a limited rebalancing of charges away from generators.

ACER published on 16 April its recommendation to the European Commission on changes to the Tariffication Guidelines in Regulation 838/2010 from 1 January 2015.

ACER stated that the increasing interconnection and integration of the European market implies an increasing risk that different levels of generator charges distort competition and investment decisions in the internal market. In order to limit this risk ACER said it is important that generator charges are cost-reflective, applied appropriately and efficiently and, to the extent possible, in a harmonised way across Europe.

In particular the Agency considers:

- energy-based generator charges (€/MWh) shall not be used to recover infrastructure costs and therefore, except for recovering the costs of system losses and the costs related to ancillary services where cost reflective energy-based charges could provide efficient signals, energy-based charges should be set to zero;
- different levels of €/MW charges or lump sum charges, as long as they reflect the costs of providing transmission infrastructure services to generators, can be used to give appropriate and harmonised locational signals for efficient investment in generation. For example to promote locations close to load centres or where the existing grid can accommodate the additional generation capacity with no or minimal additional investments; and
- ACER therefore considers it unnecessary to propose restrictions on cost-reflective capacity based generator charges and on lump sum charges.

If ACER's recommendations are approved, which looks likely, the issue of remaining within the Tariffication Guidelines would cease to be relevant in terms of meeting a restriction, although the Agency also argues in favour of harmonised charges across Europe more generally.

In terms of relevant CUSC objectives, however, by aligning charging structures with European neighbours CMP227 facilitates the objectives of increasing competition in the generation of electricity but also would reflects the full implementation of the European internal market due to be implemented from 2014. The competitive benefits would be felt in GB and within the wider European market, but it would also demonstrably support the better attainment of applicable objective (d).

4.7 Conclusion

CMP227 would enhance security of supply. It would reduce costs to generators and help to ensure plant can stay on the system to help manage increasing intermittency and the effects of closure of older coal fired stations under emissions legislation. This could have a significant impact in respect of gas plant which may otherwise be mothballed or closed.

The proposal would reduce the cost of the Capacity Market to consumers by decreasing the bids generators would need to place into the scheme. These benefits would be increased with the stated intention of the government to open up the capacity market to interconnected plant from year 2.

Aligning GB costs with European markets and regulations, which is anyway envisioned by applicable objective (d), would aid competition by allowing our generators to compete on an even footing with generators in other European markets. This should lead to an increase in demand which could increase the profitability and lifespan of UK generators currently facing difficult market conditions. The European Commission's decision on the Tariffication Guidelines is still awaited, but this proposal aligns charges with neighbouring markets and reduces distortion in competition and investment signals across the internal market while promoting cross border trade and security of supply.

We argue that all of the benefits of increased security of supply, lower wholesale costs and reductions in support costs through the Capacity Mechanism would accrue to consumers, not either/or. Reduction in costs for generators will make them more competitive, allowing extra exports of energy. The cost of remaining fixed charges will be spread over the MWhof production, further lowering wholesale prices. This also allows generators to recover more of their required income from interconnected markets reducing the required support from GB customers.

CMP227 is different from CMP201 in material respects, although it shares the same aim of enabling generators to compete on a more level playing field and some of the same arguments in their support apply. A key difference is that TNUoS charges form a fixed cost to generators, and one that is high, rising and unpredictable, and which can have a direct bearing on a decision on whether to keep a plant open. A further difference is that demand is clearly better placed to bear TNUoS risks than generators, whereas a case may be made that this is not so obviously the case for BSUoS.

We consider Ofgem's analysis for CMP201 was incomplete as it ignored the effects reducing costs to generators would have on subsidies, leading to lower overall costs to consumers. These arguments apply no less for CMP227. The regulator also considered consumers would be detrimentally affected by higher wholesale prices; however, higher wholesale prices[9] should result in greater security of supply and result in overall lower costs while dampening wholesale price volatility.

[9] It is by no means clear anyway that under the GB bilateral market that higher priced demand would be paid by GB customers.

5 Possible consumer impacts of CMP227

This short note is an attempt to quantify the headline benefits and costs to consumers of CMP227. The three main areas of consideration are the reduction in wholesale prices from removing residual TNUoS charges to generators, the increase in consumer TNUoS charges and the reduction in Capacity Market subsidy payments.

5.1 Increase in Demand TNUoS

Based on National Grid's 2018-19 initial view of TNUoS tariffs[10] demand residuals would increase from £42.09/kW to £50.19/kW. This is based on consumers covering the £2775.7mn not covered by locational TNUoS costs over the 55.3GW half hourly equivalent charging base. This is an estimated increase of £448mn.

5.2 Decrease in Capacity Market subsidy costs

This is covered in detail in the main report but it is estimated that reducing TNUoS costs to generators could result in a £248mn reduction in consumer costs in the first year of the scheme.

5.3 Reduction in wholesale prices

Gauging the reduction in wholesale prices is difficult and based on a number of different assumptions. We have estimated the impact of reduction in wholesale prices by looking at the impact on the marginal plant, which we expect to be a 1GW CCGT with 50% efficiency.

Removing the £4.93/kW residual could reduce the wholesale price between £0.80/MWh and £1.8/MWh depending on the running regime of the plant (baseload or peaking). National Grid assumes a demand of 307TWh in 2018-19; this could equate to a saving of between £247mn and £576mn.

5.4 Impact on consumers

Assuming a modest reduction in wholesale prices consumers would benefit by at least £47mn in 2018-19 as a result of CMP227. This takes into account benefit from reductions in wholesale prices (£247mn) and the Capacity Market (£248mn) less the increase of TNUoS charges (£448mn). It could rise upwards towards £376mn (£576mn + £248mn - £448mn) dependent on how the reduction in TNUoS charges feed through to plant in different running regimes. This does not take in to account further benefits identified but not quantified arising from lower CfD FiT payments, reduced SBR and DSBR payments in the interim and other benefits from more optimal usage of interconnectors.

[10] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

Annex 8 – CCGT Load Factor paper prepared by Cornwall Energy

Date: February 2015

CMP227 Analysis

ASSESSMENT OF IMPACT ON THE MARKET ASSUMING A CLOSED ECONOMY

Prepared by: Cornwall Energy

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Contents

1 Executive summary

- This paper has been prepared in response to National Grid analysis prepared for the CMP 227 workgroup which calculated the impacts of changing the Generation: Demand (G:D) split on the electricity market.
- We agree that savings from the reduction in the G:D split are not cumulative between both the energy and capacity markets.
- We do not agree that using a model where generators always seek to recover the same returns even under different market conditions is the appropriate approach.
- Generators will sell their power based on their forecasts of the cost of the marginal generator on the system and as such this is a more appropriate way of setting the power price under the model, rather than assuming generators always recover the same amount of money across the whole market.
- We have developed a competing model which calculates the power price based on a marginal gas fired generator in zone 15 with a load factor of 30%. This has the effect of increasing the impact of the reduction in the residual charge on the energy market.
- Capacity Market prices are far below what many market commentators expected, and £19.4/kW is below what many consider to be the Operation & Management (O&M) costs of a gas fired generator. This is due to the competitive pressure forcing bidders to accept low prices.
- Therefore we would expect reductions in Transmission Network Use of System (TNUoS) charges will be passed on through lower wholesale energy prices. If reductions in the G:D split are passed onto consumers through lower wholesale prices then a 1% reduction in the G:D split would result in a £0.13/MWh reduction in wholesale prices, meaning a £41.2mn benefit to consumers. However, this would be partly offset by the £25mn increase in demand TNUoS tariffs resulting in a final benefit to consumers of £16.5mn.
- The weakness of the approach of using an assumed marginal generator is that the identity of the marginal generator can change depending on location, gas/coal price dynamics as well as demand and time dynamics.

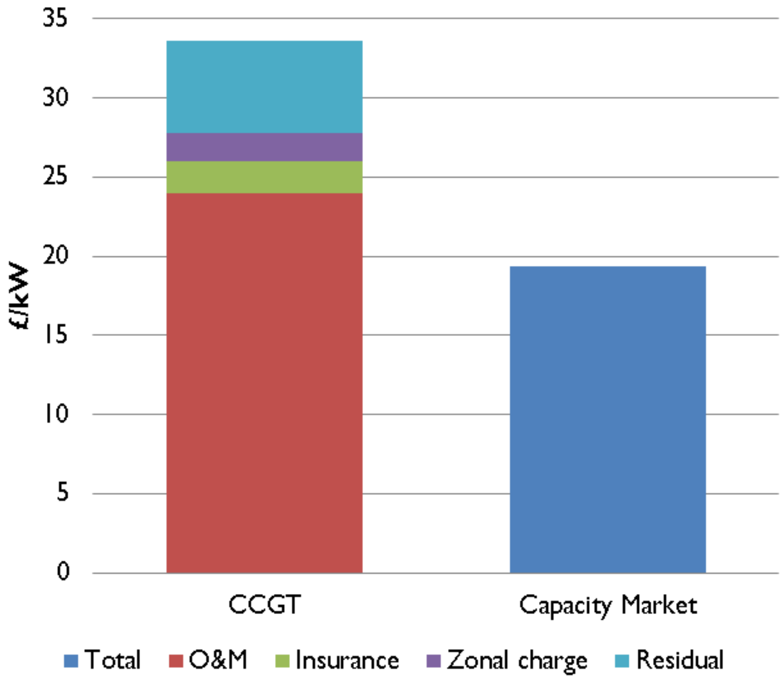
2 Capacity Market and TNUoS

Capacity Market prices out-turned below what many market commentators expected, and £19.4/kW is below what many consider to be the O&M costs of a gas fired generator. Our view is that competitive pressure forced bidders to accept lower prices under the assumption that something is better than nothing.

Figure 1 demonstrates that the clearing price of £19.4/kW is below the fixed costs for a Combined Cycle Gas Turbine (CCGT) according to the 2013 costs of generation report published by DECC[1]. This indicates the desire for plant in the Capacity Market to achieve a contract, and underlines the competitive pressure on prices.

Figure 2 plots TNUoS charges against capacity and compares successful and unsuccessful capacity (existing, new and refurbished) in the Capacity Market by TNUoS charge. We would argue that because the majority of unsuccessful capacity was in TNUoS zones with prices below £10/kW that TNUoS was not a major factor in Capacity market success and other factors, such as age, were more important drivers of the bidding behaviour and clearing price in the Capacity Market. Figure 3 demonstrates how (excluding new-build plant) the attrition in CCGT bids occurred in plant that were over 10 years old.

Figure 1 cost of generation compared to Capacity Market payment



[1] https://www.gov.uk/government/publications/decc-electricity-generation-costs-2013

Figure 2 Successful capacity and unsuccessful capacity in the Capacity Market by TNUoS charge

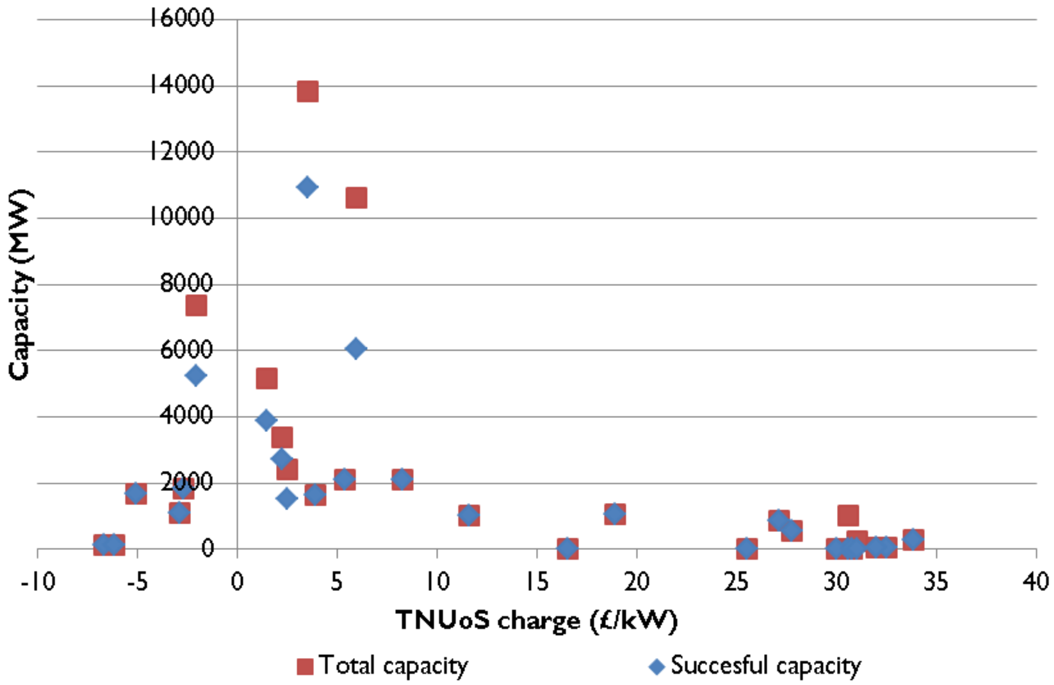
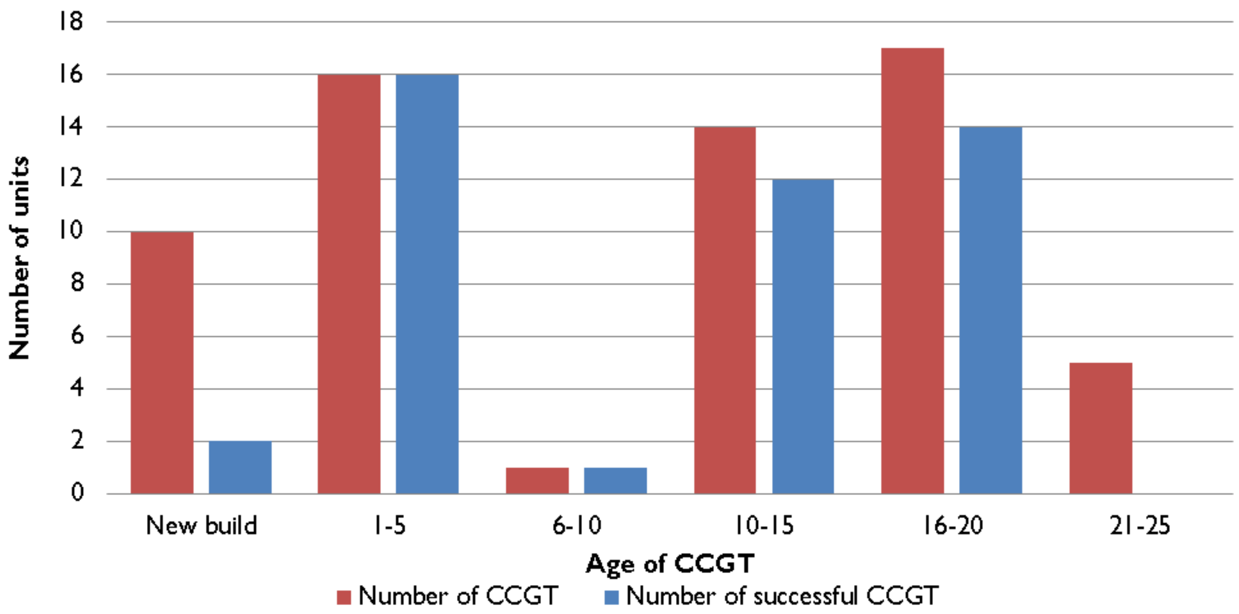


Figure 3 Successful CCGT capacity and unsuccessful CCGT capacity in the Capacity Market by age



3 Money flow model

We have re-built the model used by National Grid and changed some important assumptions. The major change is that the Capacity Market price remains stable as a result of competitive pressure keeping prices down and reductions in TNUoS are reflected in wholesale prices as a result. The method of setting wholesale prices is also different, we do not assume generators seek to make stable rents; instead we set the power price using the cost of the expected marginal generator, a 500MW CCGT in zone 15 and a 50% efficiency.

We have chosen to base the power price on the cost of the marginal generator as we believe this better reflects how the power price is set. Power prices are set based on the forecast of what the marginal generator will be. We believe this better reflects the effects on industry and power prices compared to flat values of return, as different generators face different costs.

As a result, our model differs from National Grid's in showing that a 1% reduction in the G:D split results in a £0.13/MWh difference in wholesale prices, which benefits consumers by £41.2mn, this is partially offset by a £25mn increase in the demand residual.

Table 1 results

Scenarios	Today	1	2	3
G:D split	73-27	74-26	85-15	100-0
Supplier costs	£ 18,331.2	£ 18,314.7	£ 18,133.8	£ 17,887.0
Energy costs	£ 15,567.3	£ 15,526.1	£ 15,072.7	£ 14,454.4
Transmission costs	£ 1,808.2	£ 1,833.0	£ 2,105.5	£ 2,477.0
Security costs	£ 955.6	£ 955.6	£ 955.6	£ 955.6
Generator payments	£ 16,523.0	£ 17,068.9	£ 16,028.3	£ 15,410.0
Power price (£/MWh)	£ 48.8	£ 48.7	£ 47.2	£ 45.3
Capacity Price (£/kW)	£ 19.4	£ 19.4	£ 19.4	£ 19.4
Power price difference		£ 0.13	£ 1.55	£ 3.49
CM cost difference		£ -	£ -	£ -
Transmission cost difference		£ 24.8	£ 272.5	£ 371.6
Energy costs difference		-£ 41.2	-£ 453.4	-£ 618.3
Total difference		-£ 16.5	-£ 181.0	-£ 246.8

3.1 Assumptions

The National Grid model assumes generator rents always remain the same as the change in the residual will affect all generators equally. The model then makes sure the required rent is always recovered by changing the wholesale price.

Our model assumes the power price is independent of the rent the generators seek to recover. We assume the wholesale power price is set by the marginal generator in the energy market which is assumed to be a 50% efficient CCGT. Our model also assumes the Capacity Market price remains stable as a result of competitive pressure keeping the price low, and that reductions in TNUoS do not feed through into it.

3.2 Data

Data used for the starting scenario:

- Transmission tariffs for 2014/15 including the assumptions used in their derivation i.e. generation charging base of 73GW and demand charging base of 55.3GW. This is the same assumption as National Grid.
- System energy for the year 2014/15 is assumed to be 319TWh. This is the same assumption as National Grid.
- Capacity Mechanism clearing price and size is as reported from the December 2014 auction result as 49.26GW at £19.40/kW. This is the same assumption as National Grid.
- Power price based on:
    - average gas price over the year 2014 as 50.20p/th;
    - 500MW CCGT with Efficiency of 50%;
    - all in carbon price of £20.3/t with emissions factor of 0.41t/MWh;
    - BSUoS of £1.7/MWh;
    - zone 15 TNUoS of £1.80/MWh plus generation residual of £5.81/kW; and
    - an assumed load factor of 30%.

3.3 Model

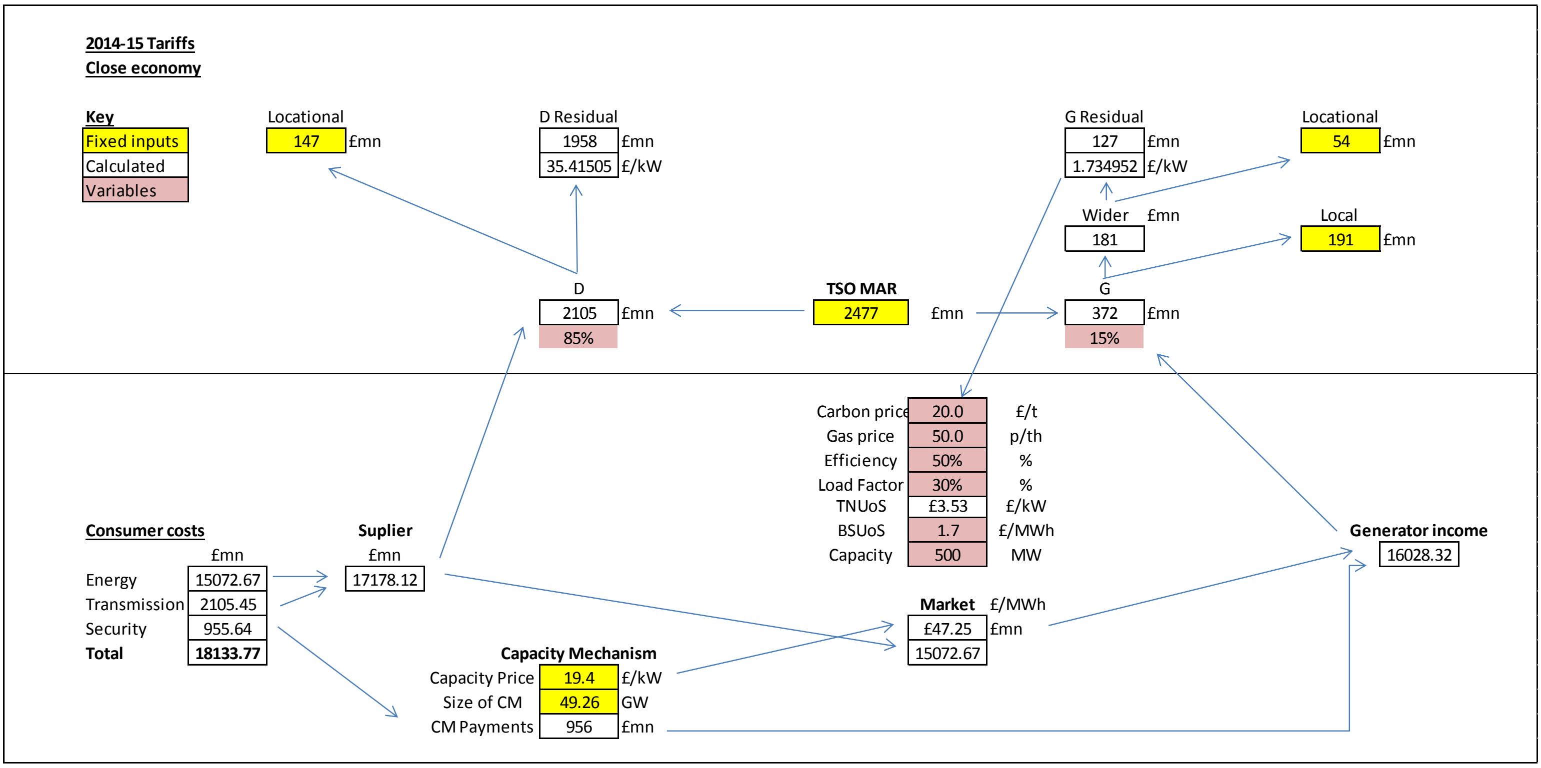
The same modelling structure (with the exception of the power price) is used to determine the impacts of changing the G:D split on the market.

Consumers pay Suppliers and contribute to subsidy mechanisms such as the Capacity Mechanism (modelled here, but the principle also applies to Contract for Difference strike prices). Suppliers procure energy from the market and pay National Grid transmission charges which are either fixed (locational demand charges) or vary with the G:D split (demand residual). Both the market and capacity mechanism revenues finance Generators. Generators also make a contribution to National Grid's transmission charges which are either fixed (locational generation charges) or vary with the G:D split (generation residual).

Figure 4 below demonstrates the flow of money under a 73:27 G:D split.

The variables in pink can be varied to reflect alternative scenarios, for instance changing the generation residual downwards increases the demand residual. The capacity price is reduced by the difference between the generation residual in the 27:73 scenario and the new residual in the chosen scenario. The market price is also recalculated by calculating the cost of the marginal generator under assumed load factors and a new TNUoS charge.

Figure 4 2014-15 Tariffs closed economy model



Annex 9 – National Grid paper on the Impact of a Fixed versus Flexible G:D Split on TNUoS Tariff Volatility

The Impact of a Fixed versus Flexible G:D Split on TNUoS Tariff Volatility

BACKGROUND

1 The CMP227 Working Group has proposed a number of WACMs:

Implementation	12m	24m	36m	48m
G:D split fixed at 15:85	Original	WACM1	WACM2	WACM3
G:D split variable and based on €0.5/MWh	WACM4	WACM5	WACM6	WACM7
G:D split fixed at 4:96 (equivalent to €0.5/MWh at current exch rate)	WACM8	WACM9	WACM10	WACM11

2 It has been proposed to undertake further analysis to understand the impact of a variable versus a fixed G:D split on the volatility of TNUoS tariffs as it is argued that generators will have less volatile tariffs if the G:D split is fixed.

3 The analysis looks at charge volatility by looking at historical data with and without a CMP224 type cap, but using a lower cap than the current €2.5/MWh to ensure the cap "bites" over the whole analysis period.

METHOD

4 The original Transport and Tariff model was re-run using data going back to 2011/12 through to 2015/16 for two scenarios:

(a) A fixed 15:85 G:D split;

(b) A G:D split based on a cap of €1.4/MWh (the minimum level required for the cap to bite in 2011/12). In this scenario the G:D split changes from 21:79 to 14:86 over the 5 year period as the cap increasingly bites.

5 The models were run using assumptions made at d-14m (C5 forecast) and d-2m (Final tariffs) for each year. It is important to note that allowed revenue, and the generation and charging bases are different from year to year.

6 The average HH demand tariff and average generation tariffs were then noted for each scenario and the variance between C5 and Final tariffs noted.

EXPECTED RESULTS

7 A fixed G:D split does not fix the absolute amount of revenue to be recovered from generators, and upon which tariffs are based. However a G:D split that is variable, and dependent on a pre-determined cap, offers more tariff stability when the cap bites because the revenue to be recovered from generators is then fixed. When there is a significant gap between the EU limit (Flexible) and the Fixed G:D split, Represent NG in working groups to develop the commercial framework tariffs can go both up and

down so a Fixed G:D split could increase volatility compared to Flexible. When the cap doesn't bite, a variable G:D split offers no difference than a fixed G:D split in terms of actual volatility when comparing t-14m with t-2m tariffs. The diagram below illustrates this point:

	Cap does not bite	Cap bites
Fixed % G:D Split	G revenue undefined therefore tariff levels can go up or down	[EU law overrides fixed G:D split, so only viable as long as the split returns a revenue that does not cause a breach of the €/MWh cap]
G:D split based on €/MWh cap	G revenue undefined therefore tariff levels can go up or down	G revenue defined therefore key tariff level determinant fixed

8 The results are therefore testing whether the statement in the bottom right hand corner of the above matrix can be seen empirically using historical data.

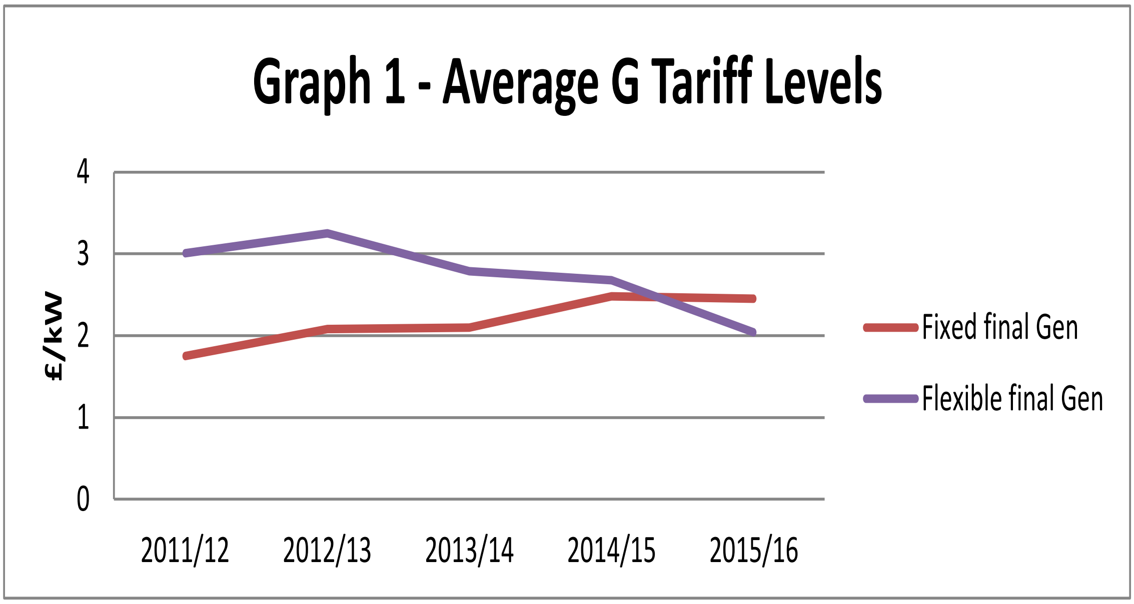
RESULTS FROM DATA ANALYSIS

9 The table below shows the core assumptions used in calculating the tariffs for the above scenarios:

Assumptions	C5 2011/12	Final 2011/12	C5 2012/13	Final 2012/13	C5 2013/14	Final 2013/14	C5 2014/15	Final 2014/15	C5 2015/16	Final 2015/16
Energy (TWh)	314	312	313	315	315	316	318	321	327	320
Limit (€/MWh)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
NG Revenue (£m)	1726	1724	1812	1949	2442	2153	2458	2477	2650	2637
X (€/£)	1.20	1.20	1.20	1.13	1.14	1.18	1.25	1.16	1.20	1.22
G (variable)	0.21	0.21	0.20	0.20	0.16	0.17	0.15	0.16	0.14	0.14
D (variable)	0.79	0.79	0.80	0.80	0.84	0.83	0.86	0.84	0.86	0.86
G.R (£m)	366	364	364	390	386	375	356	386	382	366
D.R (£m)	1360	1360	1448	1559	2056	1779	2102	2091	2268	2270
G (fixed)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
D (fixed)	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
G.R (£m)	259	259	272	292	366	323	369	372	398	396
D.R (£m)	1467	1466	1540	1656	2076	1830	2089	2106	2253	2241

10 The table containing the average tariffs that result from the above input data for HH demand and generation tariffs can be found in Annex 1. The data in the tables are presented in graphical form below.

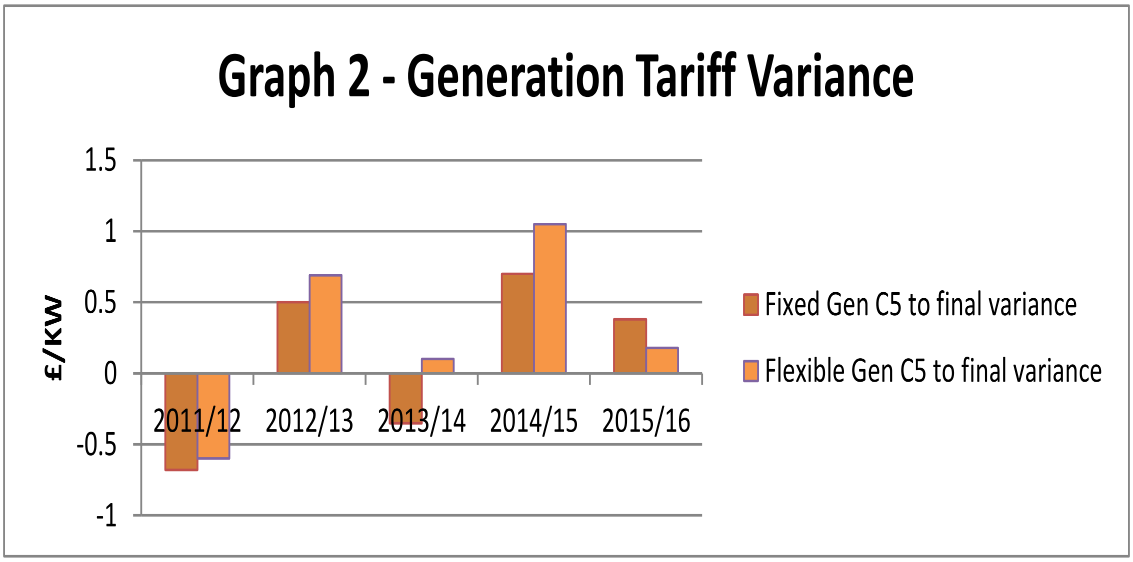
11 Graph 1 shows how absolute levels of average generation tariffs change over the 5 year period.



12 The graph shows that average generation tariff falls from 2011/12 to 2015/16 for the capped (flexible) scenario, despite the overall revenue collected from generation remaining broadly the same. This illustrates that revenue is only one aspect influencing the level of charges and other factors are causing the slight downward fall.

13 The tariff level for the fixed 15:85 split would be expected to rise until revenue collected from generation reaches the level of the €1.4/MWh cap. From 2015/16, the red line would follow the blue line as the cap would override the fixed G:D split (the split should be 14:86 rather than 15:85).

14 Graph 2 compares the average generation tariff variance over the 5 year period.

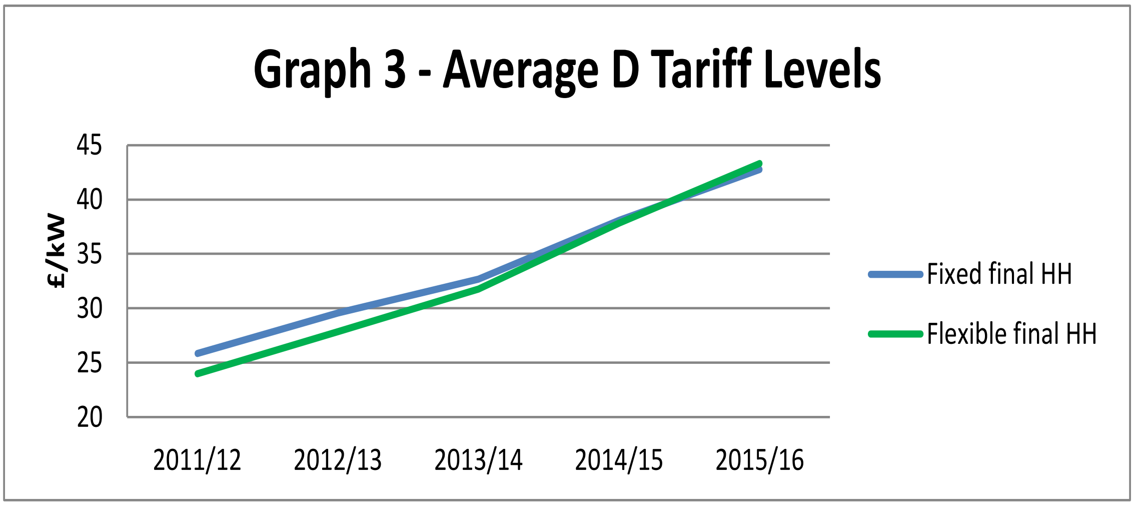


15 Graph 2 shows that a fixed G:D split led to marginally less variance between t-14m to t-2m forecasts in 2 out of the 5 years tested (2012/13 and 2014/15).

16 What this shows is that using historical data, other factors are swamping any effect a fixed or variable G:D split has on the volatility of generation tariffs. Such factors might include a Price Control or Caithness Moray, for example, which would have a larger

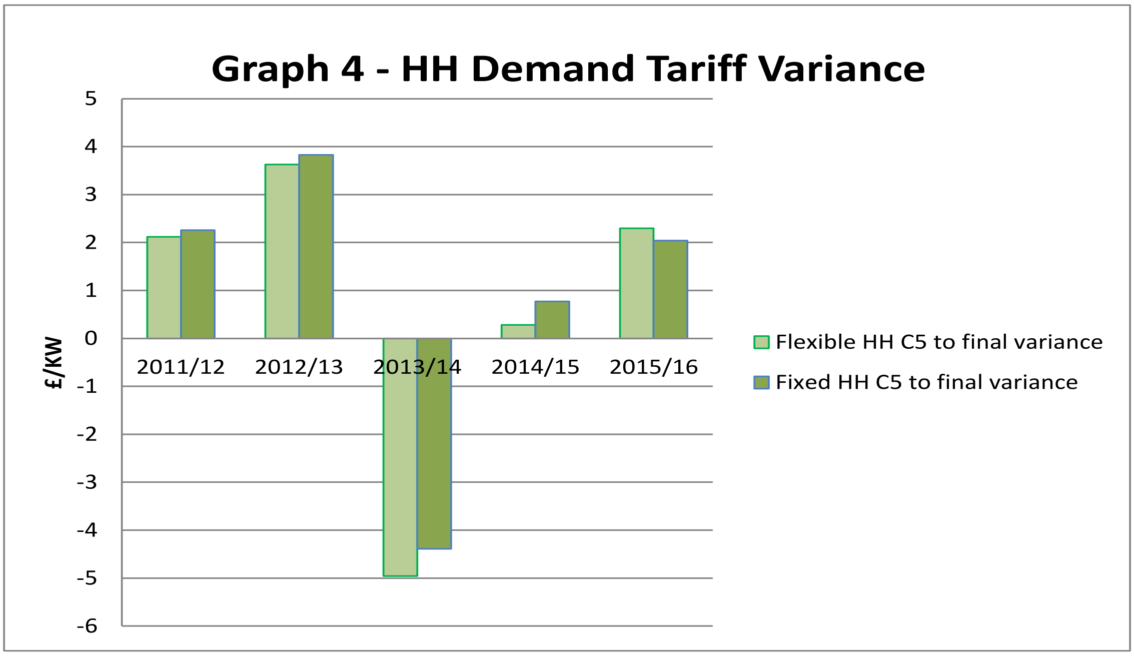
effect on average tariffs than a fixed or variable G:D split affecting t-14m to t-2m forecasts.

17 Graph 3 shows the change in average HH demand tariff levels.



18 Clearly, as National Grid’s allowed revenue increases, HH demand tariff levels rise.

19 Graph 4 compares the average HH demand tariff variance over the 5 year period.



20 Again, the graph shows very little difference in the HH demand tariff variance between fixed and flexible G:D split with the fixed G:D split leading to less variance in two out of the 5 years.

CONCLUSION

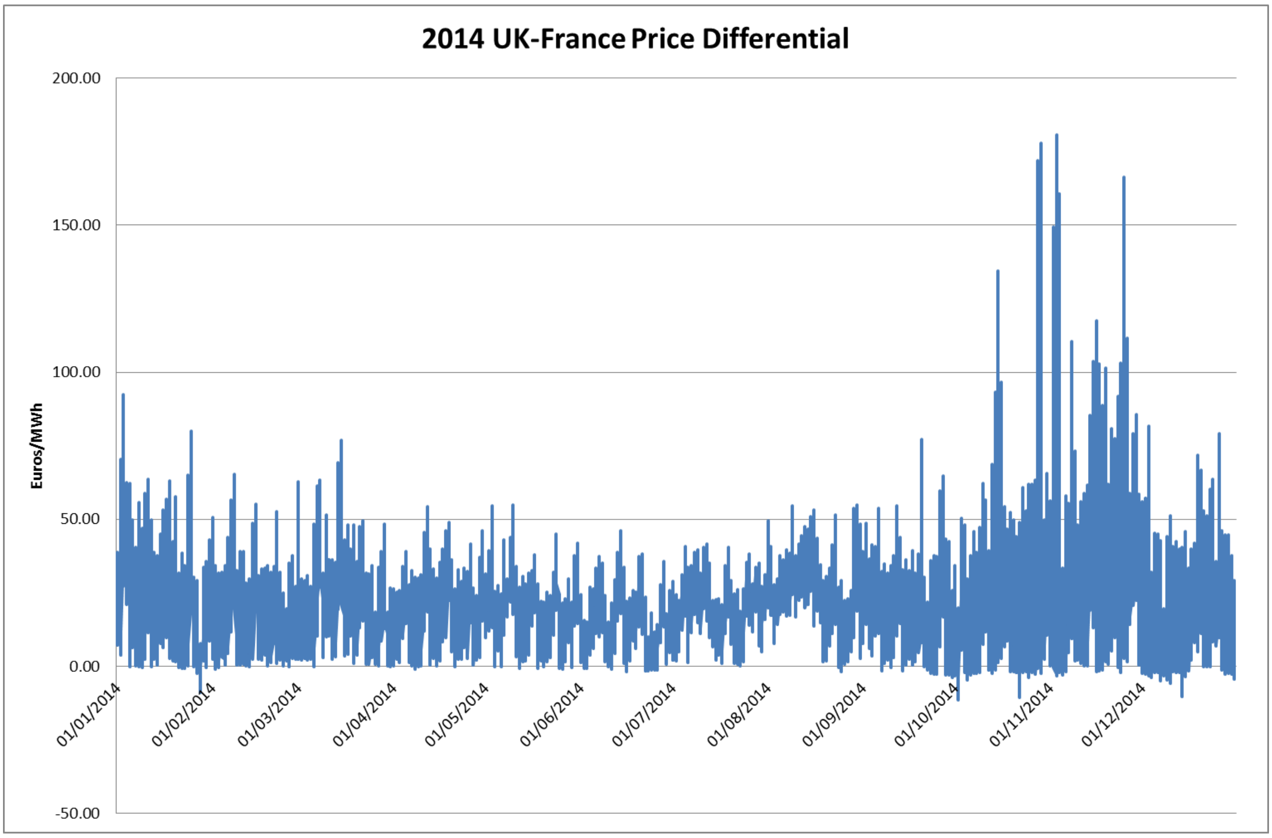
21 Whilst it might be possible to infer rationally how a fixed or variable G:D split affects tariff volatility, it can be seen that it is not a significant factor when applied to historical data.

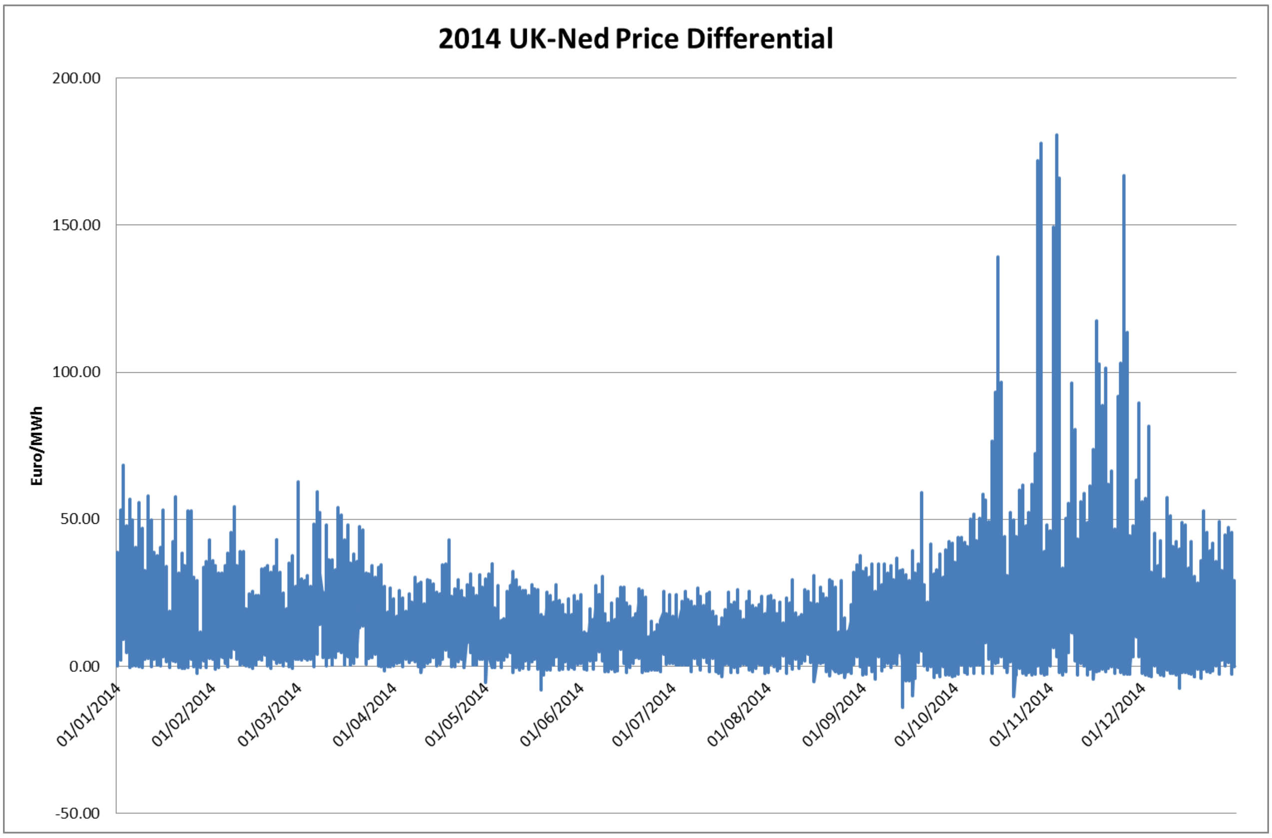
ANNEX 1 – TARIFF COMPARISON

	C5 2011/12	Final 2011/12	Variance	C5 2012/13	Final 2012/13	Variance	C5 2013/14	Final 2013/14	Variance	C5 2014/15	Final 2014/15	Variance	C5 2015/16	Final 2015/16	Variance
Average HH Tariff (Fixed G:D)	23.59	25.85	2.26	25.75	29.58	3.83	37.07	32.68	-4.39	37.31	38.08	0.77	40.73	42.77	2.04
Average HH Tariff (variable G:D)	21.87	23.99	2.12	24.21	27.84	3.63	36.72	31.76	-4.96	37.53	37.81	0.28	41.02	43.32	2.3
Average Gen Tariff (Fixed G:D)	2.43	1.75	-0.68	1.58	2.08	0.5	2.45	2.1	-0.35	1.78	2.48	0.7	2.07	2.45	0.38
Average Gen Tariff (variable G:D)	3.61	3.01	-0.6	2.56	3.25	0.69	2.69	2.79	0.1	1.63	2.68	1.05	1.86	2.04	0.18

*NHH demand has not been modelled as tariff changes that apply to HH demand would be broadly replicated in NHH demand.

Annex 10 – HH UK-France and UK-Netherlands price differential data for 2014





Annex 11 – Workgroup Consultation Responses

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

Respondent:	*Phil Whyman*
Company Name:	*Banks Renewables Ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We believe reducing the proportion of TNUoS paid by GB generators is a beneficial step in reducing costs in the energy market, ensuring security of supply and cutting the costs of low-carbon electricity. GB currently has the highest level of generator transmission charges in the EU, according to the latest overview of European transmission tariffs by ENTSO-E. Lowering or removing this charge could ensure that GB generators are in a position where they are no longer unduly disadvantaged against their competitors through allocation of a disproportionate share of regulated costs. This proposal will align costs with interconnected markets, and reduce distortions in competition between neighbouring states. This proposal would therefore benefit national security of supply through increasing demand for GB generation. We are also concerned about the predictability of TNUoS charges, so reducing or removing the residual will limit the exposure of generators to changes in charge and reallocate the risks to suppliers who can recover these costs from consumers and better manage the risks. This proposal would also benefit consumers who would see lower costs of subsidies, especially in the competitive mechanism of the Capacity Market and, of relevance to us, the Contract for Difference Feed-in-Tariffs (CfD). CfDs require generators to take a view of going forward costs and bid in a £/MWh strike price bid they envisage will cover these, reducing costs to renewable generators will lower the cost burden on consumers and help the UK to meet its low-carbon objectives more cost effectively.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	In our view all the options under CMP227 will better facilitate the applicable objectives than the present set of arrangements. In respect to Objective A (facilitating competition) it will enable GB generators to compete on a more equal footing with their EU counterparts. In addition increased certainty in TNUoS charging will enable more effective planning and encourage competition. In respect to Objective C (taking proper account of developments in transmission licensees' businesses) the proposals will help generators manage the increasing size and volatility of TNUoS charges which are resulting from the increased investment in transmission infrastructure to support low carbon objectives. In respect to Objective D (compliance with European Regulation) it will help create a more level playing field with European generators and therefore reflect the spirit and implementation objectives of the internal market.
2	**Do you support the proposed implementation approach?**	We support implementation on 1 April 2016. This strikes a balance between giving enough time to allow for industry to adjust commercial contracts and allow for the realisation of benefits as soon as possible. In our view it is important this change can be reflected in CfD strike price bids at the earliest opportunity, taking into account practical considerations.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	TNUoS is a major fixed costs to generators and reducing this charge will have a positive effect on generator dispatch costs for conventional generators and any costs renewables generators seek to recover through subsidy mechanisms (such as the CfD) and through bids on the balancing market.

Q	Question	Response
6	**What impact do you believe CMP227 will have on market prices and costs?**	We believe reducing costs to generators will affect market prices by lowering them. Generators facing lower fixed costs will need to recover less revenue in the energy market. We are aware that analysis by Cornwall Energy, considering a marginal 1GW CCGT plant, indicates that removing the £4.93/kW residual could reduce the average wholesale price between £0.80/MWh and £1.8/MWh (estimating the reduction in wholesale prices is difficult because of the range of assumptions). Based on National Grid's demand forecasts from the Future Energy Scenarios, this could result in a saving of between £247mn and £576mn. Outside of the wholesale market, in our view the proposal should also result in lower strike prices being needed by renewables generators under the Contract for Difference tariffs, further reducing costs to consumers.
7	**What impact do you believe CMP227 will have on competition?**	We believe the impact on competition will be positive. The first area CMP227 will improve competitiveness would be in competitiveness between generators across interconnectors. Reducing costs to GB generators will allow them to compete on a more equal footing with generators in interconnected markets. This will support the development of the internal market in Europe through enabling the appropriate economic signals to be sent. The proposal would also provide a more stable charging environment for generators, enabling better planning and decision making, which would also enhance competition.
8	**What impact do you believe CMP227 will have on consumers?**	We believe the consumer will benefit from this proposal. Consumers are already paying for the generator residual in wholesale power prices, CMP227 should not result in an increase in costs to consumers. In addition impacts on bills from other subsidy mechanisms such as the Capacity Mechanism and CfDs will be lowered as generators will need to recover less money through these support routes to cover their costs. In the case of the CfD the reduction in costs should allow the UK to meet its low-carbon objectives more effectively.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	We would like to ensure the effects on subsidy mechanisms, security of supply and integration with European markets are fully considered.

Q	Question	Response
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	We do not consider any other changes are required other than those required to *Section 14 Part 2 –Section 1 The Statement of Use of System Charging Methodology*.

25th September 2014

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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 **24th September 2014** 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 Jade Clarke at jade.clarke@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:	*Andy Manning 07789 575553*
Company Name:	*British Gas*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	No objectives are better met, with potentially a detrimental impact on objective (a). Arguments are presented that this will facilitate more effective competition for generators with European counterparties. Whilst it is clear this will reduce costs for GB generators it is not possible to understand the impact on competition of an isolated, piecemeal change. There are many differences in market arrangements and it is necessary to assess in the round to understand whether this change is reducing or increasing market distortions. This was noted by Ofgem in its assessment of CMP201 - 'we have concerns that the benefits of levelling the playing field will not be achieved due to existing market distortions' Also, by placing increased cost and risk on suppliers this change will potentially have a detrimental impact on competition. To be clear, objective (d) is not of relevance to this modification. Simply changing the G:D split to a different fixed level does not ensure compliance with the limit on transmission charges set out by the European Commission. At best it 'kicks the can down the road'. Although we have issues with CMP224, it does seek to deal with this limit in an enduring fashion. If CMP224 is approved by the Authority, then CMP227 has no impact on ensuring compliance as this will already be delivered by CMP224.

Q	Question	Response
2	**Do you support the proposed implementation approach?**	To ensure suppliers are given sufficient notice of this proposed increase in charges, we would suggest a minimum notice period of 3 years is necessary. Although we have not been able to properly assess the supporting evidence provided by the proposer and so cannot place too much weight on its findings, this appears to offer support to implementing in 2018. The most clearly quantified benefit to customers is the impact on the Capacity Mechanism. It would seem sensible, if this modification was to be implemented, to introduce this change in line with the introduction of the Capacity Mechanism to ensure that customers do not have an unnecessary period of detrimental impact without this offset. This is a common-sense approach to implementation we would ask the WG to consider in order to give some protection to customers.
3	**Do you have any other comments?**	
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at* cusc.team@nationalgrid.com

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	As capacity charges do not affect the marginal costs of a generator there should be no effect on dispatch or spot market prices. The ACER guidance confirms for capacity (power) based charges: *'In markets with a high level of competition, power-based G charges have no effect on the dispatch of power plants, as they do not increase the generation costs for the generators and hence SRMC remain unchanged'* and *'... in fully competitive markets, the price at which the generator offers its production into the spot market equals its SRMC.'*

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

Q	Question	Response
6	**What impact do you believe CMP227 will have on market prices and costs?**	As TNUoS for generators is a capacity (power) based charge it is not straightforward to understand the impact on market prices and costs, as recognised by the proposer's supporting document :*'Gauging the reduction in wholesale prices is difficult...'* As explained above, spot market prices should be unaffected. What is clear, including from the analysis provided by the proposer, is that it is not sufficient to assume that these costs will simply be 'passed through' and so the customer is held neutral. The proposal simultaneously claims that customers will be held neutral as the reduction in generator TNUoS will be reflected in wholesale costs and also that it will assist some plant to avoid mothballing. Clearly, those plant must be expecting to retain some of the TNUoS reduction so how this is consistent with customers being neutral needs explanation. This reinforces that the effect on market prices is not straightforward and needs to be assessed before the impact of this modification can be understood.
7	**What impact do you believe CMP227 will have on competition?**	As explained above, whilst it is clear this will reduce costs for GB generators it is not possible to understand the impact on competition of an isolated, piecemeal change. There are many differences in market arrangements and it is necessary to approach in the round to understand whether this change is reducing or increasing market distortions. Also, by placing increased cost and risk on suppliers this change will potentially have a detrimental impact on competition. We would note that we believe risk is simply moved from generators to suppliers under this modification, and not reduced or increased. This is because this modification only affects the residual element of the TNUoS tariffs. Generators are more exposed to the more volatile locational element of TNUoS charges but that is unchanged by this modification so is not relevant. Generation and demand would appear to be similarly exposed to changes in the residual element.

Q	Question	Response
8	**What impact do you believe CMP227 will have on consumers?**	CMP227 will cause a definite and direct increase of costs to customers of around £450m per year, or £7 per customer, if implemented from April 2018. Benefits should accrue to customers over the longer-term. However, this has not yet been quantified by the WG and it is not clear if and when this benefit will offset the definite increases. So it will definitely be an increase in costs for customers in the short-term, with a risk of costs remaining higher as this longer-term impact has yet to be assessed.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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 **24th September 2014** 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.

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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*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. In the context of the EU Regulation 838/2010 and CMP224, there is benefit to all parties, including customers, in removing uncertainty around the G:D split component of the TNUoS tariffs going forward and helps to improve the predictability of tariffs. The implications to the relative competition between suppliers and generators needs to be properly understood, however, in order to fully assess the merits of the Original Proposal and any potential Working Group Alternatives. Any potential short term costs to customers' needs to be balanced against any potential longer terms benefits that may feed through. We anticipate that any perceived short term increase in costs could be mitigated by sufficient notice of any change to the G:D split.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	With the appropriate implementation notice period it is possible that the Original Proposal and potential Working Group alternatives could satisfy Applicable Objective A, although the affect on relative competition needs to be understood. Subject to any decision by the EU Commission to revise the tariff limit in Regulation 838/2010, it would also facilitate Objective D in the context of a longer term horizon for any potential change to the G:D split. Notwithstanding some of the Working Groups consideration around treatment of the generator residual component, it is not clear whether the Original Proposal or potential Working Group Alternatives improve cost reflectivity and therefore achieve Objective B.
2	**Do you support the proposed implementation approach?**	We support a 2 charging year lead time following an Authority decision in order to give sufficient notice and lead time for generators and suppliers to properly take this change in to account in their contracting and trading arrangements and for costs and prices to adjust accordingly. This will also mitigate against any short term detrimental impact to costs to the customer.
3	**Do you have any other comments?**	We have no additional comments to those made in answer to the consultation questions.

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	We do not wish to raise a WG Consultation Alternative.

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	We do not think that changes to generator TNUoS costs will have a direct bearing on generators short run marginal dispatch costs in the short to medium term. In the longer term the change in generator cost base may have a bearing on the amount of available generation, which may result in greater competition in generation and therefore dispatch costs. This has to be considered in the context of wider changes in the market, not least the Electricity Market Reform Capacity Market and Contract for Difference regimes.
6	**What impact do you believe CMP227 will have on market prices and costs?**	With sufficient implementation notice of a change, we would expect market prices and costs to adjust accordingly in a timeframe consistent with the implementation of that change. The additional certainty provided by the Original Proposal and any potential Working Group Alternatives around the G:D split going forward would help to reduce any risk premium applied by suppliers and generators for this component of the transmission cost, notwithstanding remaining uncertainty associated with TNUoS tariff setting.
7	**What impact do you believe CMP227 will have on competition?**	In considering the potential reallocation of costs from generation to demand we think the effect on relative competition between suppliers and generators needs to be considered furthered. It is not clear whether this should be conducted by the working group or would form part of any potential impact assessment by Ofgem.
8	**What impact do you believe CMP227 will have on consumers?**	Whilst there is a potential short term increase in cost risk to consumers as a result of existing contracted positions of parties in the market, this could be mitigated with sufficient notice of any change taking effect, as we have highlighted in our response to question 2 above. Notwithstanding this and the implications to relative competition between suppliers, in a competitive generation market any reduction to generators cost base should feed through to wholesale prices. As the proposal is essentially seeking to recover the same costs through a different route, consumers should be broadly neutral to any potential change to the G:D split.

Q	Question	Response
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	We have no additional comments to make.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	We have no additional comments to make.
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	We have no additional comments to make.

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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 **24th September 2014** 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 Jade Clarke at jade.clarke@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)**	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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	The number proposed for the proportion of generation TNUoS charges to be paid by generation in CMP227 is arbitrary. It could increase commercial uncertainty and risk, because if this change is made, it rather invites further changes to the ratio to be proposed to new arbitrary values later on. There is some risk of adverse consumer impact in the short-term, although over time any reduction in generation residual TNUoS charges would result in reduced wholesale prices. The arbitrariness of the value proposed in CMP227 is evident in the lack of confidence with which it is proposed – 15%, or any other split(s) the working group might think of. The proper place for any attempt to harmonise differing treatments in Europe of the G:D split proportion, is via the European Tarification Guidelines. We do not believe that CMP227 better facilitates competition (objective a), as the slight uncertainty that is generated from “random” changes to the G:D split is slightly damaging to competition. We do not believe that CMP227 better, or worse, facilitates cost-reflectivity (objective b), as the TOs’ allowed revenues are still collected overall; any change to the G:D split is neutral in the extent to which objective (b) is furthered. Objective (c) – developments in transmission licensees' transmission businesses – has no relevance; objective (d) is properly being taken forward in the correct, European, arena by way of the European Electricity Tarification Guideline. Therefore overall, CMP227 is slightly worse against the four objectives, than baseline, due to being slightly worse against (a)
2	**Do you support the proposed implementation approach?**	We note that there isn’t a proposed implementation approach, as workgroup members had a range of views, duly reported in the consultation document. These range from implementing CMP227 in the next charging year after its approval by The Authority, to waiting 36 months. EDF Energy’s view is that at least two full charging year’s notice is vital to any change of this nature. This would ensure efficient business planning by generators and Suppliers alike and help to soften the short-term consumer impacts.

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

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	After sufficient time, any reduction in generation residual TNUoS charges would result in reduced wholesale prices, as well as slightly reduced bid and offer prices. This effect might not be immediate.
6	**What impact do you believe CMP227 will have on market prices and costs?**	See reply to question 5. Reduced TNUoS charges could be reflected in reduced future capacity and SBR prices and in some CfD FiT strike prices where the timescales for tendering for these, falls after a decision on CMP227 (if it were passed), so that at least in these areas there could be offsetting reductions in appropriate consumer cost elements to the prompt increase in consumer TNUoS costs from the appropriate time. A long notice period to implementation could also soften the short-term consumer impacts.
7	**What impact do you believe CMP227 will have on competition?**	Relatively little – our interconnection, as an island, is inevitably limited compared to the degree of interconnection within the central European synchronous area and its wider continental landmass. We accept that across most (but not all) of the EU, generators as a class do pay a lower share of TNUoS than in GB; the policy instrument to address this and move towards harmonisation in a measured way, at a pace that avoids the risk of short-term consumer disbenefits, is the EU Electricity Tarification Guideline.
8	**What impact do you believe CMP227 will have on consumers?**	See reply to question 5 and 6.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	Yes, section 4 captures the diverse views of the workgroup

Q	Question	Response
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	Yes, section 6 identifies the section of the CUSC that would need alteration if CMP227 were passed, and identifies no impact of CMP227 on any of Greenhouse Gas Emissions, Core Industry Documents and other Industry Documents We agree with this, on which the workgroup was in agreement within itself.

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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 **24th September 2014** 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 Jade Clarke at jade.clarke@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:	*Marta Krajewska (marta.krajewska@energy-uk.org.uk) and Kyle Martin (kyle.martin@energy-uk.org.uk)*
Company Name:	*Energy UK*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Energy UK agrees that the Workgroup Consultation has considered CMP227 against the Applicable Connection and Use of System Charges (CUSC) objectives as well as policy/regulations linked to this modification proposal. We would like to underline that the Proposal, if implemented, remains highly dependent on the actions that the European Commission will take in relation to Regulation (EU) No 838/2010 which requires an evaluation by the European Commission of an appropriate range or ranges of Transmission Use of System (TNUoS) charges recoverable from generators for the period after 1st January 2015, based on the opinion provided by ACER. The Commission may or may not choose to make changes in line with ACER's opinion which was published on the 15th April 2014. These developments require to be closely monitored as they may have an impact on the Workgroup proposals. We also understand that CMP224 will act as a backstop mechanism to ensure that GB remains compliant with the Regulation by altering the G:D split to ensure the cap on the G-charge is not breached. We therefore consider that the long term stability of TNUoS charges should be considered by the workgroup and a holistic approach needs to be taken when assessing the impact of CMP227.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	As mentioned above, Energy UK considers that the Original and all the proposed workgroup alternatives present links with the Applicable CUSC objectives listed under point (a) below. Nevertheless and as already stated, CMP227 proposals require a holistic approach and assessment, together with other CMP proposals related to the transmission charges (in particular CMP224, CMP201, CMP202), so that the barriers to the level playing field are removed for both the BSUoS and the TNUoS. *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.* *(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.*

Q	Question	Response
2	**Do you support the proposed implementation approach?**	Energy UK considers that the implementation of CMP227 should take place within reasonable and practicable timescales, with an adequate notice period, allowing prices and costs to adjust efficiently and taking into account the prevalence of forward contracting. The choice of an appropriate implementation timescale is also largely dependent on the date of an Authority Decision. If implemented, the Proposal should come into force at the start of the charging year after an agreed notice period following Authority Decision. Additionally, it should take into account a possible overlap with the Electricity Market Reform timescales. Some of our members consider that if a reduction in the G charge is more than 10% then a longer implementation period will be required. Energy UK considers that an implementation period of not less than 24 months is therefore suitable for both suppliers and generators.
3	**Do you have any other comments?**	Energy UK would like to raise the issue regarding the considerable amount of volatility in the National Grids TNUoS forecasts. We consider it appropriate to review the impact of regular changes in the G:D split arising from CMP224 against the static charges that the proposals under CMP227 would offer. Greater accuracy in National Grids TNUoS forecasts would be beneficial to both generation and demand users as well as the consumer.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	We do not wish to raise any other WG Consultation Alternative Request.

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	Energy UK considers that the proposed changes to TNUoS are unlikely to affect the short-run marginal costs. However, Energy UK also believes it might affect the long term composition of available generation, it might change what dispatch costs are available in the market.

6	**What impact do you believe CMP227 will have on market prices and costs?**	In the short term Day-to-day spot prices would not be affected by the changes proposed under CMP227. Nevertheless, the risk premium put on generators in the short-term is not negligible. TNUoS changes would need to be reflected in the overall costs for any power plant that is currently under construction. The risks for suppliers in the short time should not be overlooked. Additional modelling, illustrating how the flow of electricity to and from Europe would impact the UK should be carried out to support the view that in the long term the market should factor in reduced fixed costs when making investment decisions, which would lead to reduced market prices, in particular peak market prices. Due to the complexity of any modelling we envisage Ofgem carrying out this work as part of its Impact Assessment. It should also be noted that the potential impact of CMP227 on short-term prices and marginal costs in the short term could have a negative effect on consumer prices. This could then further justify the implementation period of not less than 24 months, as specified in question 2.

7	**What impact do you believe CMP227 will have on competition?**	In principle, CMP227 should ensure a more competitive position of the GB generators towards European counterparts. As noted in the consultation, ENTSO-E publishes an overview of transmission tariff changes applied to generators in Europe. However, we consider that additional information should be sought from other European TSOs, ENTSO-E and ACER to ensure the data is robust to allow an accurate comparison can be made between the UK and other European countries TNUoS charges. This could then be used to further support the view that the changes to the G:D split proposed under CMP227 would put the GB transmission charges more in line with those from other EU countries, where the generators either do not face a similar charge at all, or face it at much lower cost. This is a particularly important element given the upcoming implementation of the European network codes Capacity Allocation and Congestion Management (CACM) and Forward Capacity Allocation (FCA), which contribute to the completion of the European internal electricity market. In the long-term, CMP227 could improve the predictability of TNUoS charges for generators, at least for the residual component of the charge This should be counterbalanced by the assessment of risks for suppliers and their impact on the competition .

8	**What impact do you believe CMP227 will have on consumers?**	As noted in CMP201 which proposed moving BSUoS charges onto demand users, similar economic issues are consistent with CMP227. Namely that in an open market, competition is increased if parties trade on an equal basis with the opportunity that higher profit margins should attract additional investment. Removing market distortions should facilitate provision of correct signals for efficient investment decisions, which would ultimately be expected to benefit consumers across GB and the EU. In the short term there might be further costs added to consumer bills. Additional modelling illustrating how the flow of electricity to and from Europe would impact the UK should be carried out with regard to the long term benefit for GB consumers resulting from the suggested price reallocation between generators and suppliers. Due to the complexity of any modelling we envisage Ofgem carrying out this work as part of its Impact Assessment. CMP227 should be assessed on its merits, this modification seeks to rectify a defect in the CUSC which creates a distortion between TNUoS charges in the UK and Europe. However this also needs to take account of the impact of other policies which impact the realisation of these savings, such as the carbon price floor, country specific taxes and greater harmonisation of charges across Europe etc.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	We do not have any additional analysis on the impacts on CMP227.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	We do not see any other issues on top of those identified by the Workgroup and set out in Section 4.
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	We do not see any other impacts on top of those identified by the Workgroup and set out in Section 6.

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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 **24th September 2014** 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 Jade Clarke at jade.clarke@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:	*William Chilvers*
Company Name:	*ESB*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	We are supportive of the principal of reducing the G:D split but feel that the proposed split of 15:85 does not go far enough in addressing the relevant CUSC objectives, and that the ultimate aim of any amendment should be to reduce the spilt down to 0:100 as per the suggested Workgroup Alternative. Such an approach would minimise the impact of the change for both generators and suppliers and better facilitate the relevant CUSC objectives in 3 main ways: 1. Increase competition within the GB generation market by removing a volatile cost element (CUSC Objective (a)) 2. Increase competition within the generation market by aligning transmission costs for GB generators with their European counterparts whilst ensuring compliance with relevant EU regulations (CUSC Objectives (a) (c) (d)) 3. Better reflect the relative costs that generation and demand contribute to the GB transmission system (CUSC Objective (b)) <u>Increasing competition within the GB generation market</u> Volatility in transmission charging is one of the major risk factors faced by GB operators of, and investors in, GB generation assets. There is a real danger that if this transmission charge volatility continues plant may be forced to shutdown, reducing the level of competition in the GB generation market and raising concerns around security of supply. Although reducing the G:D split to 15:85 would go some way to reducing the impact of volatile transmission charges, generators would still face a significant cost that cannot be hedged. Reducing this cost element to zero over time and placing it on demand where it can better be managed would not only benefit existing plant but also make the investment environment more favourable for those developing new plant in GB, increasing the likelihood of new plant coming onto the system in the future. When compared to the status quo of existing capacity being mothballed and limited investment appetite in new capacity, removal of TNUoS charges from generation would increase competition in the GB generation market, better fulfilling CUSC Objective (a).

Q	Question	Response
		<u>Increasing competition for GB generation within the European market</u> As the European market becomes increasingly harmonised and we move towards the European internal market it is important that GB generation is price competitive with the rest of Europe, a key element of which is comparative transmission charging. Although it is difficult to analyse transmission charges across Europe on a like-for-like basis it is clear that GB transmission charges are out of line with the majority of other European nations. With many countries' generation tariffs set to zero and increasing European regulatory price controls on generation transmission charging, we are of the view that there is downward pressure on the transmission charges incurred by generators across Europe. With this in mind the only way GB will be able to effectively compete across the increasingly harmonised European market will be to bring transmission charges in line with the rest of Europe. Thus we are supportive of a reduction in the G:D split, with an eventual view to bringing the split down to 0:100 as per the Workgroup alternative. Bringing transmission charges in line with the rest of Europe would not only allow GB generators to effectively compete in the wider market but also make GB an attractive investment opportunity for new generation. As well as increasing GB competitiveness from a market perspective, a reduction to the G:D split would also allow the GB market to fulfil it's obligations under the EU Tarification Guidelines. We are encouraged by the analysis that suggests that even taking a conservative 15:85 G:D split GB would not be in breach of it's obligations up until 2021, even under the worst case scenario. However, further reducing the split to 0:100 over time would also insulate GB from any similar EU regulations that may be enacted in the future, removing the need for further modifications at a later date. We note the discussions held within the working group regarding the ACER recommendations. We would stress that these are currently only recommendations and that any decision by the regulator related to CMP227 should not be based on an assumption of how these recommendations may be treated by the European Commission but rather against the backdrop of current statutory obligations.

Q	Question	Response
		<u>Better reflection of relative costs</u> We are firmly of the view that it should be demand rather than generation that bears use of system costs. At the most fundamental level, generation output is only put onto the system to ensure demand is met. By placing 100% of use of network charges onto demand this would better reflect the relative cost that demand has on the system, thus better facilitating CUSC Objective (b).
2	**Do you support the proposed implementation approach?**	We agree that any changes should be introduced from the 1st of April to avoid any changes mid-charging year. Given the potential for breaching EU regulations within charging year 2015/16 we would suggest that any change be implemented 12 months following notification to avoid the risk of a breach. Although we are in favour of reducing the G:D split to 0:100 we are mindful that implementing such a reduction immediately could have a negative impact on the market. We therefore propose a graduated approach which would see the ratio reduce over a number of charging years. This would give industry a chance to factor the changes into future budgets and hedging strategies over time, thus minimising the impact on both consumers and generators.

Q	Question	Response
3	**Do you have any other comments?**	Although a variation of CMP227 would address issues related to competition and cost reflectivity within TNUoS charging it does not address the important issue of TNUoS volatility. Volatility within TNUoS charging is a major issue for both generators and consumers, who find it difficult to forecast and hedge these volatile charges. Despite National Grid generating quarterly TNUoS revenue recovery forecasts these are prone to large variations between forecasts and often do not align with outturn recovery. We would therefore encourage further assessment and industry wide discussion of how best to manage this volatile price element.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website*[1]*, and return to the CUSC inbox at* *cusc.team@nationalgrid.com*

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	When determining the cost of running a plant all cost factors are taken into account, one of which is the TNUoS charge. In the event that TNUoS costs were to be reduced this would naturally feed into plant running cost calculations, leading to a reduction to the cost of dispatching the plant. Also, as noted in the Cornwall Energy analysis, reduced TNUoS charges would not only be reflected in wholesale market and balancing mechanism dispatch costs but would also feed into running cost calculations for plant bidding into the competitive auctions for the Capacity Mechanism and FiT CfD, thus leading to a reduction in the overall cost of these schemes to consumers.

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

Q	Question	Response
6	**What impact do you believe CMP227 will have on market prices and costs?**	We believe that reducing the G:D split will have an overall positive effect on market prices and costs, with a greater reduction leading to a greater price benefit for all market players. In the short term the change is likely to be broadly cost neutral, with the increased charges being faced by consumers being reflected in lower cost of dispatch and therefore lower wholesale market prices. We do not share Ofgem's view that reduced wholesale costs will increase prices as any impact from increased European demand is likely to be counteracted by the increased competition that trading in the wider European market provides. In the longer term we believe that a reduction in TNUoS charges will provide a net reduction in market prices and costs as the lower risk investment climate that is likely to result will encourage new, more efficient plant onto the system. The reduced cost volatility that this change would deliver would be realised in the wholesale markets through lower prices. We would legitimately expect that this reduction would be passed to consumers by suppliers.
7	**What impact do you believe CMP227 will have on competition?**	As outlined in our response to Q1, we believe that reducing the G:D split will have a positive effect on competition both in the GB and wider European markets.
8	**What impact do you believe CMP227 will have on consumers?**	As per our response to Q6, we believe that amending the G:D split will have a positive effect on cost to consumers. We are also of the view that increased TNUoS charging for consumers would provide further incentive for large scale consumers with load shifting or demand reduction capabilities to utilise these in order to avoid these charges. Encouraging this behaviour would provide a benefit to the system as a whole.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	Not at this time.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	Not at this time.

Q	Question	Response
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	Not at this time.

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

Respondent:	*Graeme Cooper – Executive Director*
Company Name:	*Fred.Olsen Renewables Ltd.*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We believe reducing the proportion of TNUoS paid by GB generators is a beneficial step in reducing costs in the energy market, ensuring security of supply and cutting the costs of low-carbon electricity. GB currently has the highest level of generator transmission charges in the EU, according to the latest overview of European transmission tariffs by ENTSO-E. Lowering or removing this charge could ensure that GB generators are in a position where they are no longer unduly disadvantaged against their competitors through allocation of a disproportionate share of regulated costs. This proposal will align costs with interconnected markets, and reduce distortions in competition between neighbouring states. This proposal would therefore benefit national security of supply through increasing demand for GB generation. We are also concerned about the predictability of TNUoS charges, so reducing or removing the residual will limit the exposure of generators to changes in charge and reallocate the risks to suppliers who can recover these costs from consumers and better manage the risks. This proposal would also benefit consumers who would see lower costs of subsidies, especially in the competitive mechanism of the Capacity Market and, of relevance to us, the Contract for Difference Feed-in-Tariffs (CfD). CfDs require generators to take a view of going forward costs and bid in a £/MWh strike price bid they envisage will cover these, reducing costs to renewable generators will lower the cost burden on consumers and help the UK to meet its low-carbon objectives more cost effectively.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	In our view all the options under CMP227 will better facilitate the applicable objectives than the present set of arrangements. In respect to Objective A (facilitating competition) it will enable GB generators to compete on a more equal footing with their EU counterparts. In addition increased certainty in TNUoS charging will enable more effective planning and encourage competition. In respect to Objective C (taking proper account of developments in transmission licensees' businesses) the proposals will help generators manage the increasing size and volatility of TNUoS charges which are resulting from the increased investment in transmission infrastructure to support low carbon objectives. In respect to Objective D (compliance with European Regulation) it will help create a more level playing field with European generators and therefore reflect the spirit and implementation objectives of the internal market.
2	**Do you support the proposed implementation approach?**	We support implementation on 1 April 2016. This strikes a balance between giving enough time to allow for industry to adjust commercial contracts and allow for the realisation of benefits as soon as possible. In our view it is important this change can be reflected in CfD strike price bids at the earliest opportunity, taking into account practical considerations.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	TNUoS is a major fixed costs to generators and reducing this charge will have a positive effect on generator dispatch costs for conventional generators and any costs renewables generators seek to recover through subsidy mechanisms (such as the CfD) and through bids on the balancing market.

Q	Question	Response
6	**What impact do you believe CMP227 will have on market prices and costs?**	We believe reducing costs to generators will affect market prices by lowering them. Generators facing lower fixed costs will need to recover less revenue in the energy market. We are aware that analysis by Cornwall Energy, considering a marginal 1GW CCGT plant, indicates that removing the £4.93/kW residual could reduce the average wholesale price between £0.80/MWh and £1.8/MWh (estimating the reduction in wholesale prices is difficult because of the range of assumptions). Based on National Grid's demand forecasts from the Future Energy Scenarios, this could result in a saving of between £247mn and £576mn. Outside of the wholesale market, in our view the proposal should also result in lower strike prices being needed by renewables generators under the Contract for Difference tariffs, further reducing costs to consumers.
7	**What impact do you believe CMP227 will have on competition?**	We believe the impact on competition will be positive. The first area CMP227 will improve competitiveness would be in competitiveness between generators across interconnectors. Reducing costs to GB generators will allow them to compete on a more equal footing with generators in interconnected markets. This will support the development of the internal market in Europe through enabling the appropriate economic signals to be sent. The proposal would also provide a more stable charging environment for generators, enabling better planning and decision making, which would also enhance competition.
8	**What impact do you believe CMP227 will have on consumers?**	We believe the consumer will benefit from this proposal. Consumers are already paying for the generator residual in wholesale power prices, CMP227 should not result in an increase in costs to consumers. In addition impacts on bills from other subsidy mechanisms such as the Capacity Mechanism and CfDs will be lowered as generators will need to recover less money through these support routes to cover their costs. In the case of the CfD the reduction in costs should allow the UK to meet its low-carbon objectives more effectively.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	We would like to ensure the effects on subsidy mechanisms, security of supply and integration with European markets are fully considered.

Q	Question	Response
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	We do not consider any other changes are required other than those required to *Section 14 Part 2 –Section 1 The Statement of Use of System Charging Methodology*.

25nd September 2014

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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 **24th September 2014** 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 Jade Clarke at jade.clarke@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:	*Tom Breckwoldt* *Tom.breckwoldt@gazprom-energy.com*
Company Name:	*Gazprom Marketing & Trading Retail Ltd ("Gazprom Energy").*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We prefer the current G:D split for apportioning TNUoS costs been generation and demand. However, if a change is progressed we believe that it is essential that whichever option is chosen provides: i. A sufficient notice period for implementation (36 months) so that existing contracts are not impacted (both wholesale and supply contracts). ii. Certainty/stability of the G:D split going forward. We do not believe competition would be benefitted by uncertainty each year of what the G:D split would be. 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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	As outlined in the workgroup consultation document, we believe there are arguments to be made for and against CUSC objective (a) being better facilitated. The reduction in TNUoS costs for generators may see GB generators able to compete more effectively with European generators. However, from the supplier perspective there would be an increase in unpredictable TNUoS costs which would need to be factored into customer contracts. We believe 15:85 is the best option should any change be progressed, as it gives certainty over the G:D split, which a number of the alternatives do not. We would favour certainty/stability of the G:D split in this way over a related modification CMP 224.
2	**Do you support the proposed implementation approach?**	We do not support an implementation date earlier than April 2018.
3	**Do you have any other comments?**	No.

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	No comment.
6	**What impact do you believe CMP227 will have on market prices and costs?**	No comment.
7	**What impact do you believe CMP227 will have on competition?**	Our main concern is regarding the proposed implementation dates. We believe implementation should be April 2018 at the very earliest. We are strongly against implementation in April 2016 or April 2017. A change in the G:D split will lead to significant changes in TNUoS charges and there needs to be a sufficient lead time for a change of this magnitude to be factored into contracts. An earlier implementation date runs the risk of windfall losses or gains.
8	**What impact do you believe CMP227 will have on consumers?**	The change should be neutral to consumers, providing that a reduction in generators TNUoS costs lead to an equivalent reduction in wholesale prices. As stated in the question above, it is important that there is a sufficient notice period of any change in the G:D split so contracts do not need to be amended mid-term.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No.

Q	Question	Response
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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Respondent:	*Simon Lord*
Company Name:	*GDF-Suez*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: ……………..

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	Yes we believe that reducing the G/D split towards G=0 is the right direction of travel. It will allow GB generators to compete more effectively in Europe and will reduce the fixed cost faced by marginal generators and hence increase the supply of this type of generation in GB.
2	**Do you support the proposed implementation approach?**	Yes we support a timely but measured implementation approach over 12-24 months.

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

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	Whilst it is unlikely to have a direct effect on the dispatch cost a lower TNUoS cost would affect the closure decision for marginal generators. Lower TNUoS would lead to more plant availability and hence reduced cost to consumers driven by competition amongst generators.
6	**What impact do you believe CMP227 will have on market prices and costs?**	See above
7	**What impact do you believe CMP227 will have on competition?**	See above
8	**What impact do you believe CMP227 will have on consumers?**	See above
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	Yes
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	Yes

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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Please send your responses by **24th September 2014** 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 Jade Clarke at jade.clarke@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:	*Debbie Houldsworth*
Company Name:	*Haven Power Ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	We do not believe that there is enough justification to immediately move to a G:D split ratio of 0:100 when any of the other potential options put forward will fulfil the applicable CUSC objectives with less disruption to consumers, especially given the fact that there appears to be a majority view in the workgroup that would propose an implementation timetable of less than three years.
2	**Do you support the proposed implementation approach?**	
3	**Do you have any other comments?**	This modification will have different impacts depending on the size and business model of the parties and, as a consequence, will have a different impact on their customers. For example, smaller suppliers may have less resource to devote to interpreting information and forecasting of future TNUoS values. We do not believe that this has been taken in to account when determining the lead times for implementation. There is no small supplier representation on the working group, and the impact of the changes on the customer base of smaller suppliers / new entrants should also be taken in to consideration when looking at the implementation timescales – especially give the increase in customers that are choosing to be supplied by them.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com*

Specific questions for CMP227

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

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	
6	**What impact do you believe CMP227 will have on market prices and costs?**	
7	**What impact do you believe CMP227 will have on competition?**	
8	**What impact do you believe CMP227 will have on consumers?**	We believe that there would be a minimum impact on consumers provided that the adequate implementation timetables are given. Anything that would reduce the generator split of the charges by more than 15% needs at least three full charging years notice. We have calculated that there is a significant step change between the 15:85 and 4.26:95.74 provisional demand tariffs that we could see causing significant price disruption if too short a lead time is given. This is because most smaller customers tend to contract in advance for one or two years so a three year implementation timeframe will avoid significant price disruption to their prices mid-contract or large risk premia having to be included in their contract prices to take account of uncertainty faced by suppliers. Whilst larger customers sometimes contract for longer periods (up to five years) these will generally tend to be pass through, so three years would be enough time for them to factor in any changes to their budgets.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	

CUSC Workgroup Consultation Response

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

Respondent:	*Chris Elder*
Company Name:	*InterGen*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	As the proposer of CMP227, InterGen believes that reducing the proportion of TNUoS charges paid by GB generators is essential. It would bring the level of charges more closely in line with generators in other European countries, and thus enable GB generators to compete more fairly and effectively in the European market. The latest overview of European transmission tariffs by ENTSO-E shows that of the 14 countries that have any generator charge at all, Great Britain now has the highest average charge. Lowering this charge would help to level the playing field and ensure that GB generators are in a position where they are no longer unduly disadvantaged against their competitors through allocation of a disproportionate share of regulated costs. The European Commission's decision on the Tariffication Guidelines is currently awaited, but the proposal aligns charges with neighbouring markets and reduces distortions in competition and investment signals across the internal market. This proposal would therefore benefit national security of supply through increasing demand for GB generation. The proposal would also materially address the issue of predictability of TNUoS charges overall by reducing the exposure of GB generators as a class. It would reallocate the risk of the charges where they can better be managed, on suppliers that can recover these costs from consumers. Finally, we note that the proposal would also benefit consumers: a supporting paper for InterGen prepared by Cornwall Energy, which is included with the consultation, has estimated that the benefits could be between £34mn and £363mn in 2018-19. These benefits arise from a decrease in Capacity Market costs (from reduced clearing prices) and reductions in wholesale prices, which alone exceed increased demand TNUoS charges. This figure does not take account of further benefits identified but not yet quantified arising from lower payments under Contracts for Differences for new low carbon generation (as TNUoS risk is broadly passed through to consumers under this framework) and from more efficient interconnector usage. We note that a number of potential alternative proposals in respect of the appropriate G:D split have been raised. Our original proposal indicated that a revised 15:85 split was a suggestion based on the Project Transmit technical working group modelling approach could have merit, but we recognised at that stage that the workgroup might wish to consider other

	splits that lower the generation share. We welcome consideration of these potential options to ensure that the proposal or proposals that go forward are soundly based. **As we explain below our preferred solution at this stage based on the discussions of the working group is to remove the residual charge from generators.**

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	Yes. All options that reduce the share of TNUoS paid by generators will better facilitate achievement of the relevant objectives compared to the current baseline. The proposal meets objective a) in respect of facilitating competition because it will enable GB generators to compete on a more equal basis with their European counterparts. It would also provide a more stable TNUoS charging environment for generators, which would enable better planning and decision making and thereby enhance competition. The proposal will facilitate objective c) in respect of taking proper account of developments in transmission licensees' businesses. It responds to the increasing size and volatility of TNUoS charges, which are resulting from the increased investment in transmission infrastructure to support low carbon objectives. The proposal will also facilitate objective d) in respect of compliance with the European Regulation and binding decisions by it or ACER. This is because it would reflect the full implementation of the internal market due in 2014 and therefore the necessity to create a more level playing field for GB generators against the European competition. The European Commission's decision on the Tariffication Guidelines is awaited and therefore there is uncertainty over what might be compliant with the revised rules, if there is any change. The potential alternative G:D splits cover a range of options that reduce generator charges and at this stage we believe all of them should be considered further. However, on the basis of the information provided we think removal of the generator residual charge is best aligned with the applicable objectives as it is demonstrably cost reflective.
2	**Do you support the proposed implementation approach?**	Three implementation options have been proposed, assuming an Authority decision by 31 March 2015, being 1 April 2016, 1 April 2017 and 1 April 2018. We think that implementation should be at least one full charging year after an Authority decision to allow for industry adjustment of commercial contracts and suitable notice to generators in planning, consenting and building phase. However, implementation should also be timely to allow for the earliest realisation of the benefits, in particular, allowing existing and new thermal generators to factor in potential TNUoS savings in their capacity mechanism exit bids We therefore support implementation on 1 April 2016.

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

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	The proposal would lower the long run marginal costs that generators would seek to recover from energy market revenues. TNUoS charges form a fixed cost to generators and one that is high, rising and unpredictable. Lowering these costs and making them more predictable will have a positive impact on decisions for marginal generation to remain open in the medium term, and would therefore have a positive impact on both competition and on security of supply.
6	**What impact do you believe CMP227 will have on market prices and costs?**	The proposal would reduce market prices and costs. Analysis by Cornwall Energy carried out for us to help support the working group, considering a marginal 1GW CCGT plant, indicates that removing the £4.93/kW residual could reduce the average wholesale price between £0.80/MWh and £1.8/MWh (although estimating the reduction in wholesale prices is difficult because of the range of assumptions). Based on National Grid's central demand forecasts, this could equate to a saving of between £247mn and £576mn. The proposal would also reduce the cost of the Capacity Market by allowing plant to place lower bids. The Cornwall analysis has indicated that this could reduce the cost of the Capacity Market to consumers, based on a 15:85 split, by at least between £210mn and £243mn. At present, all other things being equal, the plant which is in the highest TNUoS zone will set the clearing price which will result in consumers paying the highest TNUoS charge (£/kW) multiplied by the total volume of capacity procured through the auction. The proposal should also result in lower strike prices being needed by renewables generators under the Contract for Difference tariffs, further reducing costs to consumers.

Q	Question	Response
7	**What impact do you believe CMP227 will have on competition?**	The impact on competition will be positive: GB generators will no longer be in a position of facing charges at a level well in excess of those paid by their competitors, where they face them at all. They will therefore be able to compete on a more equal basis which should see more effective competition. This will support the development of the internal market in Europe through enabling the appropriate economic signals to be sent. The proposal would also be likely to enable generators to remain open that might otherwise take the decision to shut, as they would see lower fixed costs, thus enhancing competition in generation. The proposal would also provide a more stable charging environment for generators, enabling better planning and decision making, which would also enhance competition.
8	**What impact do you believe CMP227 will have on consumers?**	The impact on consumers would be positive. The analysis by Cornwall Energy indicates that, assuming a modest reduction in wholesale prices (see answer to 6 above), consumers would benefit by at least £34mn in 2018-19 as a result of CMP227. This takes into account benefit from reductions in wholesale prices (£247mn) and the Capacity Market (£235mn) less the increase of TNUoS charges (£448mn). This benefit could rise towards £363mn depending on how the reduction in TNUoS charges feed through to plant in different running regimes. This analysis does not take account of further benefits identified but not quantified from lower Contract for Difference payments (as a reduction in network charges will enable lower strike price bids), reduced Supplementary Balancing Reserve and Demand Side Balancing Reserve and benefits from more optimal user of interconnectors.

Q	Question	Response
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	We refer you to the Cornwall Energy report prepared on behalf of InterGen, which provides analysis supporting the proposal. In particular it highlights the proposal can be expected to: ▪ enhance security of supply through reduced costs to generators; ▪ align costs the European markets and regulations, promoting efficient cross-border trade and improving security of supply through increased demand for GB generation; ▪ benefit consumers by reducing wholesale costs and the costs of the Capacity Market and Contracts for Difference to consumers which is expected to be greater than the increase in demand TNUoS; and ▪ reduce the year-on-year charging volatility seen in TNUoS charges and places the risks where they can best be managed, on suppliers.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	We have highlighted below impacts which would result from the implementation of CMP227 that are relevant to the overall consideration of the proposal. We believe the proposal will improve security of supply. In 2012 the UK mothballed or closed around 6GW of gas fired capacity as a result of deteriorating market conditions. Increasing demand to encourage the return of these stations is an efficient use of resources, as the plant represents sunk assets, and contributes to security of supply. We think the proposal would lead to a more appropriate allocation of risk as between suppliers and generators. Under CMP227 suppliers would bear an increased proportion of TNUoS costs. However suppliers are less exposed to changes to locational charges as demand zones cover larger and different areas to generation zones. Changes would therefore tend to be smoothed out when compared to generation charges. An additional benefit is the proposal should mitigate distortions between the GB markets and interconnected European markets which should lead to more efficient use of interconnection assets, allowing interconnectors to flow between markets based on comparable prices.
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	We have not identified any change other than those required to *Section 14 Part 2 –Section 1 The Statement of Use of System Charging Methodology*.

22nd September 2014

CUSC Workgroup Consultation Response Proforma

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Any queries on the content of the consultation should be addressed to Jade Clarke at jade.clarke@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 Bedford Paul.bedford@opusenergy.com
Company Name:	Opus Energy Ltd
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	No comment
2	**Do you support the proposed implementation approach?**	No. We have three year contracts quoted with effect from 1 April 2015 for which the costs are fixed, therefore, we would require a three year lead time for implementation (i.e. 1 April 2018). Any material change in the charge structure prior to this date would have a detrimental impact on our business and on our consumers.
3	**Do you have any other comments?**	No
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	No comment

Q	Question	Response
6	**What impact do you believe CMP227 will have on market prices and costs?**	Section 4.29 of the consultation document states that: CMP227 can be expected to increase the TNUoS demand charge element of customer bills, but also lead to reductions in the wholesale price, capacity market clearing price and Contracts for Difference Feed in Tariffs (CfD FiTs) strike prices subject to competitive allocation. These reductions can be expected to offset the increases to customer bills caused by the increase in the TNUoS Demand charge. <u>However, it is important that the change to the G:D split is accompanied with adequate notice to allow prices and costs to adjust efficiently and so avoid windfall gains and losses.</u> Although theoretically the change in cost to non-generators should be neutral, transmission costs for non-generators will definitely increase but it will be down to market trading conditions to offset these increases with reduced commodity prices.
7	**What impact do you believe CMP227 will have on competition?**	We would not expect any adverse impact on competition as all Suppliers are subject to the same structure.
8	**What impact do you believe CMP227 will have on consumers?**	Please see response to question 6.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	No comment
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	No comment

Thomason, Alex

From: Frank Gordon <fgordon@r-e-a.net>
Sent: 19 September 2014 17:46
To: Clarke, Jade; .Box.Cusc.Team
Cc: bw@powercon-c.com; Paul Thompson
Subject: CMP 227 Consultation response

Consultation on CMP 227 Proposal
The REA is strongly supportive of the proposals to amend distribution charges for UK generators.

Amending the TNuOS costs split to 15:85 from the present 27:73 will facilitate UK compliance with the single electricity market requirements and therefore help 'level the playing field' with European competitors.

This is essential for competition to flourish and to enable new generators to enter the market. This will be positive for UK consumers in the longer run. The proposal document clearly states that even in the short term the impact on consumers is expected to be neutral as suppliers should not be adversely affected.

We therefore believe this change proposal constitutes a logical step for the UK market and enables greater competition at no added cost to the consumer therefore should be implemented as proposed.

Kind regards,

Frank

Frank Gordon
Policy Analyst

REA
RENEWABLE ENERGY ASSOCIATION

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CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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Respondent:	*Jonathan Wisdom*
Company Name:	*RWE npower ltd*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; **We do not believe that this change has a positive impact on this objective in terms of facilitating competition in supply. We consider that the large uncertainty that this change creates by leaving open short notice periods of alteration to the split of TNUoS charges has a negative effect on competition by reducing market transparency for suppliers and customers. Large cost swings and the uncertainty of whether these will be passed on means that customers will inevitably be charged more through risk premia and businesses who may have pass-through contracts with suppliers will face large unexpected cost movements. Clarity in regulated charges increases competition by ensuring that consumers have access to a large set of products**

	from various market participants unencumbered by additional risk. This modification without sufficient lead time for implementation would detrimentally impact this transparency. **We believe that this modification is neutral to this objective in respect of generators.** (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); **We have not seen evidence through the working group to suggest that there is a positive impact on this objective.** (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses. **We believe that this change is neutral to this objective.** (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. **We believe that this change is neutral to this objective.**

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	No. However, we believe that notice periods of 24 months and 36 months respectively could be considered to be neutral to Applicable Objective (a) as opposed to having a negative impact. This is because we would expect that reduced generator costs would flow through to suppliers over this longer timeframe resulting in correct costs to consumers In the context of the split itself we believe that retaining an appropriate level of generator charging is positive to maintain locational elements of price signals to the generators and would therefore favour an 85:15 split. This also retains some of the locational signal as indicated in the ACER report and would render this proposal better than the WACM's to relevant objective (b). However, we still do not believe this is better than the baseline.
2	**Do you support the proposed implementation approach?**	We support an implementation approach as referred to above of 24-36 months to allow for the effective pass through of costs into consumer prices and to ensure there is no double charging as a result of this cost allocation. It has been acknowledged through the working group that generator costs in the short term would not see reductions from this change and therefore to have a short notice period of 12 months does not, in our view, allow for these costs to be effectively priced in to the wholesale market. If a short notice period is adopted consumers may be double charged as a result. We note that in CMP201, where the BSUoS costs were felt to reflect the short term marginal costs of the generators and therefore more likely to be passed through quickly, the workgroup felt that WACM1 (which introduced a 2 year notice period for implementation) was the best option as it mitigated any potential price distortions to consumers. Additionally many customers choose to receive TNUoS costs as a pass-through from their Supplier. Any large unexpected disturbance to these charges will cause issues for these businesses and may have wider macro economic effects. This does not appear to allow businesses the comfort of operating in a stable regime.
3	**Do you have any other comments?**	No

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*No*

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	We believe that in the medium term (2-3 years following an implementation decision) these reduced costs to generators will begin to flow through to the wholesale price. However, as established in the Working Group, TNUoS costs are considered to be operational costs by many parties and so will not figure in generator pricing decisions until later in the medium term. Therefore allowing a longer notice period to allow market prices to adjust and ensure customers are not charged twice is a crucial element of any implementation.
6	**What impact do you believe CMP227 will have on market prices and costs?**	We believe that in the medium term it is theoretically possible that the costs will pass through into the wholesale price, however, as noted above, we do not believe that this is likely until 2-3 years following the implementation of the proposal.
7	**What impact do you believe CMP227 will have on competition?**	We believe it will have a negative impact as outlined above unless appropriate notice is given.
8	**What impact do you believe CMP227 will have on consumers?**	Unless the implementation period is managed carefully with sufficient notice to parties of the cost changes we do not believe that CMP227 will have any effect other than negative. Either customers will pay more with insufficient time to react to the change (if they are pass-through) or they will be charged higher risk premia by their suppliers due to the large uncertainty in costs that this brings forward.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	Yes

Q	Question	Response
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	Yes

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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Respondent:	*James Anderson; james.anderson@scottishpower.com*
Company Name:	*ScottishPower Energy Management*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	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. (d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	ScottishPower believes that the original proposal and each of the alternatives better facilitate the applicable CUSC charging objectives. By better aligning charges faced by GB generators for the use of the transmission system in GB with charges faced by generators in Europe, CMP227 original and the alternatives level the playing field for GB generators and remove barriers to competition in the trade of electricity within the EU. This better facilitates objective (a). As CMP227 and its alternatives do not affect the locational element of the TNUoS charge and only affect the residual element which seeks to recover a certain proportion of TNUOS costs from generation, neither the proposal nor any of the alternatives affect the cost-reflectivity of the charging methodology (as the residual element is not cost-reflective) and therefore are neutral against objective (b). Better aligning GB transmission charges with those faced by generators within EU helps achieve the Single Target Model for electricity and facilitates cross-border trade thus better reflecting developments in the transmission licensees' businesses (objective c). Analysis provided under CMP224 indicates that GB is at risk of breaching the limit on transmission charges to generators (€2.50) under EU Regulation 838/2010 unless the proportion of TNUoS revenue recovered from generators is reduced. CMP227 avoids a breach of EU 838/2010 whilst providing certainty to transmission system users over the proportion of revenue to be recovered from each of generators and suppliers in the longer term. CMP227 and its alternatives therefore better meet objective (d), compliance with the Electricity Regulation and legally binding decisions of the European Commission.

Q	Question	Response
2	**Do you support the proposed implementation approach?**	ScottishPower supports the earliest practicable implementation approach for CMP227 consistent with allowing parties to take account of the proposed change in the G:D split in making their economic decisions. We believe that an implementation period of 24 months is sufficient for parties to factor this change into their generation and retail hedging decisions.
3	**Do you have any other comments?**	No.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*No.*

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	Although they have the appearance of fixed costs, charges to generators for the use of the GB electricity transmission system have to be recovered through the prices which generators charge for their output over the medium and longer term. Failure to do so would result in the closure of the generator. The requirement to provide notice of TEC changes and to pay for a full year's transmission charges in any year in which a station generates, makes any decision on whether to hold transmission capacity irrevocable within those timescales. However all generators require to review the economic decision whether to continue to operate (and at what level of capacity) in future years. Developers need to decide whether the economic case, including generator transmission charges justifies investment in new generation plant. The level of TNUoS charges, through decisions on plant closure / capacity reduction and new entry, therefore has a direct impact upon the electricity wholesale price.
6	**What impact do you believe CMP227 will have on market prices and costs?**	ScottishPower believes that any reduction in generator TNUoS costs will be reflected in reduced wholesale price costs to suppliers due to the competitive nature of the GB generation market. Through creating a level playing field with generation in interconnected markets in Europe the market for GB generation should increase, supporting retention of existing generation capacity and investment in new capacity. This, in-turn, should reduce the costs involved in securing adequate capacity margins under the Capacity Mechanism.

Q	Question	Response
7	**What impact do you believe CMP227 will have on competition?**	ScottishPower believes that CMP227 will better facilitate competition in generation across Europe. By enlarging the potential market for GB generation, CMP227 provides the opportunity for new market entrants thus better facilitating competition in GB generation.
8	**What impact do you believe CMP227 will have on consumers?**	We believe that the effects of CMP227 will be at worst neutral on GB consumers and will be potentially beneficial through improved generation margins and and reduced cost of achieving improved security of supply.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	We believe that the Workgroup has identified all the issues.
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	We believe that the Workgroup has identified all the potential impacts of CMP227.

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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Respondent:	*Colin Prestwich*
Company Name:	*SmartestEnergy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We are generally not in favour of this proposal. For reasons articulated later, we do not believe a case for change has been made. We are also concerned, should the change go ahead that there will be losses for suppliers who have locked in prices on the basis of a 73:27 assumption for some years to come. At the very least there needs to be a two year lead-time and preferably three. In addition we would make the following observations: 1. Generators are already trading their power for 2015 in the market, changing the TNUoS tariffs for 2015 will hand a windfall gain to the generators who have sold their power inclusive of an estimated TNUoS bill. 2. It is not clear why a general reduction in generation TNUoS fees is the solution for some generators being charged more than the cap. 3. Nothing in the change prevents the 15% breaching the European cap in future. It merely creates the uncertainty that there could be further changes. 4. 15:85 are just random numbers. As such, the modification cannot achieve its aim of "levelling the playing field in Europe"; it is merely tilting it in what is perceived to be the right direction. 5. Reducing the generation contribution proportion will weaken the price incentive to locate plant in the south east, increasing costs in the long run for consumers 6. The problem is really that the cost of the transmission system in the UK is too expensive.

	Whilst we are not supporters of CMP224 we believe it is preferable to CMP227 as it does have a clear aim of not breaching guidelines. The aim of CMP227 is not clear or justified.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	We do not believe that CMP227 in any guise facilitates the applicable CUSC objectives.
2	**Do you support the proposed implementation approach?**	We have concerns regarding the timing of implementation. Please see below.
3	**Do you have any other comments?**	We believe a minimum two year lead time is required for such a modification as suppliers have contracts which fix TNUoS for this period. Having said that, we are not generally in favour of this modification anyway since it has not been properly justified. The argument in 5.17 is specious nonsense. The bottom line is that suppliers can only charge through at published rates and there is no way that they could have been recovering additional monies from customers over this period.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP227

Q	Question	Response

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	No comment
6	**What impact do you believe CMP227 will have on market prices and costs?**	In a fully competitive market we would expect market prices to reduce, demand charges to increase and the net effect to be zero. However, we doubt whether this would happen in practice.
7	**What impact do you believe CMP227 will have on competition?**	None. We do not think there will be a stampede of electricity from Europe either through new build or imports. Even if GB does have the highest generator charge in Europe, we are not so interconnected that it would make any difference. Besides which, we do not believe that a proper analysis has been carried out over European charges.
8	**What impact do you believe CMP227 will have on consumers?**	We believe costs to consumers would increase, especially in the short term. It is debateable whether, all things being equal, costs would come back down to their previous level.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	Identifying the issues is one thing. Addressing them satisfactorily is another. We agree with the comment in 4.20 that there appears to be no account made of other charges European generators are liable for or whether shallow or deep charging is prevalent in Europe. It is also unclear whether the bands in the EC regulation have come about due to an understanding of the comparative costs in each country or whether they merely reflect the existing tariffs. All of the above needs to be understood if the case for change rests on comparison with Europe and to determine whether it is appropriate to aim for an average of the range or the top end.
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	No comment

it CUSC Workgroup Consultation Response Proforma

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

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	In broad terms we believe that CMP227 original and the potential options set out in Section 5 of the consultation document could, in principle, better facilitate the Applicable CUSC Objectives. However, we appreciate that they are still in the development stage and that further variances to these options (as well as additional options) may be forthcoming as the Workgroup deliberations continue.

Q	Question	Response
2	**Do you support the proposed implementation approach?**	We note the implementation approach as set out in Section 7 of the consultation document. We have considered the three options set out namely (a) 12 months, (b) 24 months and (c) 36 months. In considering the issue of implementation it is important to be mindful of the CUSC timeline. Notwithstanding what is said in paragraph 1.2 of the consultation document (about the Workgroup reporting back to the September Panel meeting) it looks likely that the earliest that the Workgroup will report back to the CUSC Panel is the October (or possibly November?) meeting which means, after the Code Administrator consultation, a CUSC Panel vote at the December (or possibly January?) meeting. Thus the Final Modification Report is unlikely to be submitted to the Authority until mid January (or possibly February). Allowing for a period of time for Ofgem to consider this change, and factoring in a possible Regulatory Impact Assessment period of at least four weeks, followed by an Authority decision, means it is highly unlikely that a decision on CMP227 will be received prior to 1st April 2015. Far more practical is a decision in spring 2015. Linking this realistic notice period and the next 1st April means the following:- i) Approve in spring 2015, 12 months from the next 1st April (2016), so actual implementation 1st April 2017; or ii) Approve in spring 2015 24 months from the next 1st April (2016), so actual implementation 1st April 2018; or iii) Approve in spring 2015, 36 months from the next 1st April (2016), so actual implementation 1st April 2019. Given this we agree that option (a), a twelve month implementation period, is appropriate as this will ensure that the manifest defect that CMP227 seeks to address, whereby generators in GB are placed at a competitive disadvantage to generators in other Member States is corrected at the earliest practical opportunity. [continued below]

Q	Question	Response
3	**Do you have any other comments?**	No. [continuation of answer to Q2] In our view, as we have set out in our response to the CMP224 Workgroup and Code Administrator consultations; the GB generation market is competitive and therefore we see no 'windfall gains and losses' arising form the implementation of this change as any reduction in generator costs will be reflected in a corresponding reduction in the GB wholesale price which will benefit suppliers and, ultimately, end consumers. Delaying the implementation of CMP227 will result in GB generators being less competitive than generators out with GB. This, in turn, will have a detrimental impact on the commercial viability of GB generators leading to a reduction in plant margin which, given the Ofgem Electricity Capacity Assessment, will have negative conations for the security of supply situation.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	We believe the case as to the effects that a change to TNUoS charges would have on generator dispatch costs has been explored at length in CMP224. We would expect, in a competitive GB generation market, that the reduction in GB generator TNUoS costs would be fully reflected back into the wholesale market price. To suggest otherwise would be to argue against the GB generation market being competitive.

Q	Question	Response
6	**What impact do you believe CMP227 will have on market prices and costs?**	As per our answer to Q5 above, we would expect CMP227 to lead to a reduction in the GB generation price to reflect the reduction in GB generator TNUoS. This reduction will, in turn, lead to a removal of the barrier to cross border trading for GB generation and enable GB generation to compete fairly with generation elsewhere in Europe. This pan European trading of electricity, as envisaged and facilitated by the introduction and application of the Third Package and its associated Regulations, Guidelines and Network Codes, will result in the GB market price converging (as expected by the Third Package) with those in other non GB markets as the Electricity Target Model comes into practical effect over the medium and longer term.
7	**What impact do you believe CMP227 will have on competition?**	In terms of the GB generation market we agree with the Authority that it is competitive at present. We do not envisage any diminution in the competitiveness within the GB generation market. However, the defect identified by CMP227 is not, per se, the competitiveness of GB generation market but rather that market's competitiveness within the pan-European generation market as we move towards the Electricity Target Model with the planned application, in the short to medium term, of the (i) CACM (ii) FCA and (iii) Balancing Network Codes. In respect to this we agree with the Proposer that CMP227 will have a positive effect on competition in generation across Europe which includes the GB generation market.
8	**What impact do you believe CMP227 will have on consumers?**	As noted in response to Q6 and Q7 we would expect the effects of CMP227 to be either neutral (at worst) or positively beneficial (at best).
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	Information in respect of this matter is likely to be commercially confidential.
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	We believe that the Workgroup has identified the issues, as set out in the consultation document, that are pertinent to assessing CMP227.

Q	Question	Response
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	We believe that the Workgroup has identified the impacts, as set out in the consultation document, that are pertinent to assessing CMP227.

CUSC Workgroup Consultation Response Proforma

CMP227 – Change the G:D split of TNUoS charges, for example to 15:85

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Respondent:	*Mary Teuton (mteuton@vpi-i.com)*
Company Name:	*VPI Immingham*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We support the proposal to reduce the proportion of Transmission charges paid for by generators to 15% (with 85% levied on suppliers). We would support this charging methodology as: 1. It is in line with the Commission Regulation (EU) No 838/2010 specifying that the average annual transmission charges paid by GB generators be between €0-2.5/MWh 2. It is a consistent year on year charge that does not need to be changed year on year, providing more certainty However, we note the modelling of the Transmission charges, as set out in Annex 4 of the consultation documents and would support further analysis of all of the options. With GB generators facing the some of the highest Transmission charge, they are unable to compete with their European counterparts. Therefore the proposal improves competition and supports the implementation of the European internal market. At the same time, the proposal should reduce future costs for consumers due to the reduction in wholesale prices that could be expected as a result of the reduction on the charge plus the expected reduction in how generators bid into the capacity mechanism.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP227 Original Proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives? Please give your reasoning.**	Yes, we believe that the original proposal better facilitates the applicable CUSC objectives, specifically: The proposal will facilitate increased competition (objective (a)) as it will enable generators in the GB market to better compete with their European counterparts. With the GB market having a significantly higher share of Transmission charges levied on generators than other European countries, a reduction would level the playing field. Also, with many gas generators in the GB market facing very low profit margins and facing difficult decisions regarding mothballing and / or closure, a reduction in the charge would enable more generators to stay open, increasing competition in the GB wholesale market. The proposal improves compliance with the use of system charging methodology results, reflecting the costs incurred by licencees (Objective (c)). Transmission charges are increasing in both size and volatility due to the increased investment required to support the transition to low carbon sources and the proposed change responds to this It will also ensure compliance with European Commission (Objective (d)), specifically to ensure that Transmission charges do not breach the prescribed range of 0 to €2.50 as set out in The Commission Regulation No 838/2010 and will reflect full implementation of the internal market which is due this year.
2	**Do you support the proposed implementation approach?**	Yes, we support the proposed implementation approach. We would support a 12 month implementation timeframe so as to better align the GB electricity market in line with European markets more rapidly, although we recognise the need to be at least one full charging year after an Authority decision. Therefore, we support an implementation date of April 2016.

Q	Question	Response
3	**Do you have any other comments?**	Many generators are facing difficult decisions regarding their futures at the same time as system margins are tightening and National Grid are looking to procure additional generating capacity via their Supplemental Balancing Reserve. With costs significantly out of line with other European countries and the distortion increasing as costs go up, the proposed change will help GB generators to compete and therefore they will be more likely to stay open. This will then contribute to security of supply, improving the system margins and reducing the potentially need for services such as the Supplemental Balancing Reserve. It will also, likely, reduce the cost of the capacity mechanism as generators will be able to bid lower into the auction.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP227

Q	Question	Response
5	**How would changes to TNUoS costs effect generator dispatch costs to generation in the GB market?**	TNUoS is a fixed cost that generators incur and it is increasing in both size and volatility. Reducing this charge would lower the long run marginal cost for generators and therefore this should be reflected into dispatch costs ultimately.
6	**What impact do you believe CMP227 will have on market prices and costs?**	We refer to the supporting Cornwall Energy analysis that we support and are in agreement with. Generators bidding into the capacity mechanism will be able to bid lower as their costs will be lower, and more certain, further reducing costs for consumers going forward. In addition, generators participating in the CfD allocation rounds would be able to bid lower, thereby either reducing costs for consumers or increasing the efficiency of the Levy Control Framework spend, as more renewable capacity could be built for the same money.

Q	Question	Response
7	**What impact do you believe CMP227 will have on competition?**	As set out in question 1, we believe that the impact on competition will be positive overall. GB generators will be able to compete on a more level basis with their European counterparts. With the GB market having a significantly higher share of Transmission charges levied on generators than other European countries, a reduction would level the playing field. This will also support the implementation of the single European market. Also, with many gas generators in the GB market facing very low profit margins and facing difficult decisions regarding mothballing and / or closure, a reduction in the charge would enable more generators to stay open, increasing competition in the GB wholesale market.
8	**What impact do you believe CMP227 will have on consumers?**	We do not believe that there would be a net impact on consumers. Suppliers will have to pick up the additional Transmission charges, but these should be more than offset by a reduction on wholesale prices and capacity mechanism costs.
9	**Do you have any additional analysis you would like to provide on the impacts on CMP227?**	No
10	**Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? If so, please provide details**	Under the Rules of the Capacity Mechanism, plant that participates and is successful in the capacity auction must maintain its TEC to the delivery year. Therefore any decision to mothball a plant in the interim period will have to also factor in the ongoing TEC costs. Although there are concerns regarding security of supply, with National Grid looking to procure additional capacity via the Supplemental Balancing Reserve (SBR), wholesale prices do not seem to be reflecting scarcity rents for Winter 2014/15. Currently, marginal plant that is out of the merit order could be expected to be loss making in the years before capacity payments start. A reduction in Transmission costs, whether the plants are mothballed or not, would improve the profitability of plants ensuring that they stay on the system and provide ongoing security of supply.
11	**Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.**	Yes

LEGAL TEXT

Original, WACM 1 and WACM 2

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 0.15 ~~27~~ or x times the total revenue, where x for a charging year n is calculated as:

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

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 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

WACM 3, WACM 4 and WACM 5

14.14.6 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:

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

vii.) 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.

viii.) 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.

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

x.) 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 0.04~~27~~ or x times the total revenue, where x for a charging year n is calculated as:

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

Where;

Cap_{EC} = 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

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