

## Stage 02: Workgroup Consultation

Connection and Use of System Code  
(CUSC)

# CMP227

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

**This proposal seeks to change the current 27:73 G:D split, reducing the proportion of TNUoS charges paid by generators to a suggested ratio of 15:85.**

This document contains the discussion of the Workgroup which formed in March 2014 to develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 8 of this document.

**Published on:** 27<sup>th</sup> August 2014  
**Length of Consultation:** 20 Working days  
**Responses by:** 24<sup>th</sup> September 2014



### ***The Workgroup concludes:***

To be completed following the Workgroup Consultation



### ***High Impact:***

All parties which are liable for TNUoS charges



### ***Medium Impact:***



### ***Low Impact:***

What stage is this document at?

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

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### Any Questions?

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## About this document

This document is a Workgroup consultation which seeks the views of CUSC and interested parties in relation to the issues raised by the Original CMP227 CUSC Modification Proposal which was raised by Intergen and developed by the Workgroup. Parties are requested to respond by 5pm on **24<sup>th</sup> September 2014** to [cusc.team@nationalgrid.com](mailto:cusc.team@nationalgrid.com) using the Workgroup Consultation Response Proforma which can be found on the following link:

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

## Document Control

| Version | Date                         | Author             | Change Reference                   |
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| 0.1     | 27 <sup>th</sup> August 2014 | Code Administrator | Workgroup Consultation to Industry |

## 1 Summary

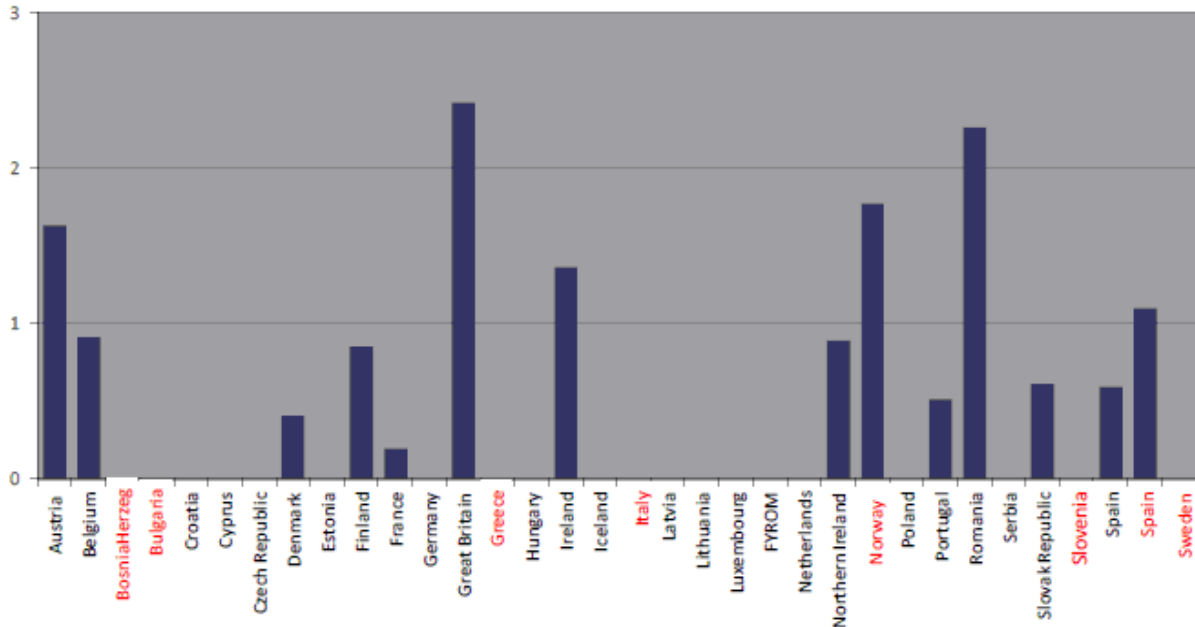
- 1.1 This document describes the Original CMP227 CUSC Modification Proposal (the Proposal), summarises the deliberations of the Workgroup and the options for potential Workgroup Alternative CUSC Modifications (WACMs). Prior to confirming any alternative proposals the Workgroup are seeking views on the options they have identified, what is the best solution to the defect and also any other further options that respondents may propose.
- 1.2 CMP227 was proposed by Intergen and submitted to the CUSC Modifications Panel (the Panel) for their consideration on 28<sup>th</sup> 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 CUSC Applicable Objectives. The Workgroup is required to consult on the Proposal during this period to gain views from the wider industry (this Workgroup Consultation). Following this Consultation, the Workgroup will consider any responses, vote on the best solution to the defect and report back to the Panel at the September 2014 Panel meeting.
- 1.3 The Workgroup first met on 3<sup>rd</sup> 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 CMP227 seeks to address. These potential options for change are highlighted within the Workgroup Alternatives in Section 5 of this document.
- 1.4 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.
- 1.5 This Workgroup 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/>, along with the Modification Proposal Form.

## 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. Figure 1 below shows the G components of the unit transmission tariffs in 2014.

**Figure 1 – G component of Transmission tariffs in 2014.**

Euro per MWh



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, 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 would reduce to 15% to comply with EU Tarification Guidelines<sup>1</sup>, and that the reduction would apply from April 2015 to March 2030. It 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.
- 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, which were the subject of consultation by the European Regulators' Group for Electricity and Gas (EREG) and provided recommendations to the European Commission, indicates that there is a movement towards lower generator charges. EREG 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.

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<sup>1</sup> Commission Regulation (EU) No. 838/2010 Page 5 of 56

### 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 would also materially address the issue of predictability of TNUoS 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<sup>2</sup>.

### 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) currently under review and the work done under the Project TransmiT SCR.
- 4.3 CMP201 'Removal of BSUoS Charges from Generation' seeks to align the GB electricity Balancing Services charging arrangements with those prevalent within other EU Member States. CMP201 proposes 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. CMP201 is currently awaiting decision with the Authority.
- 4.4 CMP224 'Cap on the total TNUoS target revenue to be recovered from Generation Users' aims to introduce a cap on the annual generation Transmission Network Use of System (TNUoS) revenue so that the annual average transmission charges payable by Generation Users in GB always stay within the current range specified by EC Regulation 838/2010 (€ zero to €2.5 / MWh). CMP224 therefore seeks only to change the G:D split if there was a risk of breaching EC Regulation 838/2010.
- 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 14<sup>th</sup> July 2014, Ofgem published a consultation<sup>3</sup> 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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<sup>2</sup> 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 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 currently does not include changes proposed under CMP201 or CMP224. However, with a decision on CMP201 and CMP224 both due this summer, the CUSC Baseline may change throughout the CMP227 Modification process.

#### **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.”*

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

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<sup>3</sup> <https://www.ofgem.gov.uk/publications-and-updates/consultation-connection-and-use-system-code-modification-proposal-224>



generators across the EU, as set out by the European Commission Regulation 838/2010, beyond December 2014.

4.12 ACER provided its opinion<sup>4</sup> 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 The Commission may choose to make changes in line with ACER’s opinion, make other changes it deems appropriate or maintain the current ranges. It is important that the value of the annual average generation transmission charges in GB remains within the current prescribed range (€zero to €2.5/MWh) and any future revised range that may come into force from 1<sup>st</sup> January 2015. The Workgroup noted that the current modification CMP224 aims to

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[http://www.acer.europa.eu/Official\\_documents/Acts\\_of\\_the\\_Agency/Opinions/Opinions/ACER%20Opinion%2009-2014.pdf](http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Opinions/Opinions/ACER%20Opinion%2009-2014.pdf)

keep the value of annual average generation transmission charges in GB within this range to avoid a breach of the EC Regulation 838/2010.

- 4.16 The Workgroup noted that the EC Regulation 838/2010 (Part B, Paragraph 5) indicates that the European Commission may make a change to the limit effective from 1<sup>st</sup> January 2015 and considered what options would be available to allow GB to change the G:D split to ensure GB stays within the new limits set out by the EC Regulation. One Workgroup member's view was that if the limit had been changed effective from 1<sup>st</sup> January 2015, GB should be compliant with the EC Regulation as of the 1<sup>st</sup> January 2015 as it is primary legislation. This would suggest a 'mid year' tariff change. It was also noted that when the CMP224 Workgroup discussed this matter, the view was that a short period between 1<sup>st</sup> January 2015 and 1<sup>st</sup> April 2015 when the GB generator TNUoS tariffs were 'non-compliant' would probably be legally acceptable as long as during the calendar year 2015, the average charges remained within the range set in the EU Regulation. This approach would avoid the need for a 'mid year' tariff change. Other Workgroup members felt that there may be some derogation allowing GB to be in breach of the regulation for a period of time as CMP224 and CMP227 demonstrate that GB are aiming towards compliance within a short period of time.
- 4.17 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.
- 4.18 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**

- 4.19 It was noted by the Workgroup that currently GB has, according to the ACER opinion, 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.
- 4.20 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”.
- 4.21 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).
- 4.22 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**

- 4.23 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.
- 4.24 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**

- 4.25 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.

- 4.26 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**

- 4.27 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.
- 4.28 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.
- 4.29 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.
- 4.30 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.
- 4.31 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 CMP223 which will come into effect in April 2016. .

- 4.32 One Workgroup member calculated an estimated shift in TNUoS costs from generation to demand if there was a change to the G:D Split. Given a 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.
- 4.33 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 €0.25/MWh tariff limit, transferring the residual tariff from generation to demand and no G:D Split.

### **Cornwall Energy Supporting Analysis**

- 4.34 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 has not yet considered or discussed the paper in detail, but wished to ensure it was available as part of this consultation.
- 4.35 Cornwall Energy has since provided an updated version of the report for the Workgroup Consultation. This paper can be found within Annex 5 of this document. Please note that the Workgroup have not read or contributed towards this report and any views expressed are those prepared by Cornwall Energy for InterGen as Proposer.
- 4.36 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**

- 4.37 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 NETA trading arrangements, but that the fixed costs of generation in GB would be recovered from a wider pool of consumers both inside and outside GB.
- 4.38 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**

- 4.39 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.
- 4.40 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.

## 5 Workgroup Alternatives

### Potential options for change

5.1 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.

#### Updated 15:85 G:D split as modelled under Project TransmiT

5.2 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).

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

- 5.3 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. 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. Some Workgroup members felt this created more of a level playing field with European competitors. 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.
- 5.4 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.
- 5.5 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 GB 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

- 5.6 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.
- 5.7 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.
- 5.8 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.
- 5.9 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 introduce a bandwidth to avoid the negative charge or have a mid year tariff change. Some Workgroup members were not supportive of a mid year tariff change.

### Generation Residual set to zero

- 5.10 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**

- 5.11 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.
- 5.12 The Workgroup discussed the four potential options for change and agreed that implementation should be at the start of the charging year i.e. 1<sup>st</sup> 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 |
|---|-----------|-----------|-----------|
| 18.3:91.7<br>(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**

- 5.13 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.
- 5.14 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.
- 5.15 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.
- 5.16 However, another member of the Workgroup noted that published analysis<sup>5</sup> 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

<sup>5</sup> <http://www.energy-uk.org.uk/publication/finish/5-research-and-reports/1069-wholesale-market-report-march-2014.html>

beyond two years out. Given this evidence the Workgroup member questions whether a 36 month notice period could be justified.

- 5.17 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.

### Impact on the CUSC

- 6.1 Changes to Section 14, Part 2 – Section 1, The Statement of Use of System Charging Methodology

### 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 At this stage, the Workgroup assumption is that, if implemented, the Proposal should come into effect at the start of the charging year (i.e. 1<sup>st</sup> April) after an agreed notice period following Authority decision. The Workgroup are consulting on whether a notice period should be given prior to implementation of CMP227 and have considered the options of 12, 24 and 36 months. To clarify, this means:
- a) Implementation on 1<sup>st</sup> April following 12 months after an Authority Decision.
  - b) Implementation on 1<sup>st</sup> April following 24 months after an Authority Decision.
  - c) Implementation on 1<sup>st</sup> April following 36 months after an Authority Decision.
- 7.2 For clarity and assuming an Authority decision on or prior to 31<sup>st</sup> March 2015, then the above options would be implemented on
- a) 1<sup>st</sup> April 2016
  - b) 1<sup>st</sup> April 2017
  - c) 1<sup>st</sup> April 2018
- 7.3 Note: Ofgem's recent CMP224 Regulatory Impact Assessment<sup>6</sup> indicates that a shorter than 12 month implementation period may be suitable (for CMP224, which for the reasons noted elsewhere in this consultation document is similar to CMP227). The Workgroup has not considered the implications of this Ofgem 'minded to' CMP224 position in terms of the implementation of CMP227. It will do so after this consultation.

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<sup>6</sup> <https://www.ofgem.gov.uk/publications-and-updates/consultation-connection-and-use-system-code-modification-proposal-224>

## 8 Responses

8.1 This Workgroup is seeking the views of CUSC Parties and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and summarised below:

Standard Workgroup Consultation questions;

- Q1:** Do you believe that CMP227 Original proposal or any of the potential options for change better facilitate the Applicable CUSC Objectives?
- Q2:** Do you support the proposed implementation approach?
- Q3:** Do you have any other comments?
- Q4:** Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider? Please see 8.3.

Specific CMP227 Workgroup Consultation questions;

- Q5:** How would changes to TNUoS costs affect generator dispatch costs to generation in the GB market?
- Q6:** What impact do you believe CMP227 will have on market prices and costs?
- Q7:** What impact do you believe CMP227 will have on competition?
- Q8:** What impact do you believe CMP227 will have on consumers?
- Q9:** Do you have any additional analysis you would like to provide on the impacts of CMP227?
- Q10:** Has the Workgroup identified all the issues, as set out in Section 4? Are there any other issues? if so, please provide details.
- Q11:** Has the Workgroup identified all the impacts, as set out in Section 6? Are there any other impacts? If so, please provide details.

8.2 Please send your response using the response proforma which can be found at the following link:

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

8.3 In accordance with Section 8 of the CUSC, CUSC Parties, BSC Parties, the Citizens Advice and the Citizens Advice Scotland may also raise a Workgroup Consultation Alternative Request. If you wish to raise such a request, please use the relevant form available at the weblink below:

[http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms\\_guidance/](http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/)

8.4 Views are invited upon the proposals outlined in this report, which should be received by **5pm** on **24<sup>th</sup> September 2014**. Your formal responses may be emailed to: [cusc.team@nationalgrid.com](mailto:cusc.team@nationalgrid.com)

8.5 If you wish to submit a confidential response, please note that information provided in response to this consultation will be published on National Grid's website unless the

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

- 8.6 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 and Confidential".

**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

## Connection and Use of System Code (CUSC)

|   |
|---|
| <b>Title of the CUSC Modification Proposal</b>  |
| Reduce the G:D split of TNUoS charges, for example to 15:85   |
| <b>Submission Date</b>  |
| 18 <sup>th</sup> February 2014  |
| <b>Description of the Issue or Defect that the CUSC Modification Proposal seeks to address</b>  |
| <p>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.</p> <p>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.</p> <p>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.</p> <p>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.</p> <p>Not implementing the proposal will mean that GB generators are increasingly disadvantaged against their European competitors as the European market continues to develop.</p> <p>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</p> |



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 undergoing 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.<sup>1</sup> 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.<sup>2</sup>

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](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/ergег\\_g\\_and\\_l.pdf](http://ec.europa.eu/energy/electricity/florence/doc/florence_11/ergег_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](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 Charging 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

|  |
|--|
| <b>Justification for Urgency Recommendation</b>  |
| Not Applicable   |
| <b>Self-Governance Recommended: Yes / No</b>   |
| No   |
| <b>Justification for Self-Governance Recommendation</b>  |
| Not Applicable   |
| <b>Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?</b>  |
| It is not believed that this proposal will interact with any ongoing SCRs.   |
| <b>Impact on Computer Systems and Processes used by CUSC Parties:</b>  |
| DCLF ICRP transport model  |
| <b>Details of any Related Modification to Other Industry Codes</b>   |
| None   |
| <b>Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:</b>   |
| <b>Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.</b>   |
| <b>Use of System Charging Methodology</b>  |
| <input checked="" type="checkbox"/> (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; |
| <input type="checkbox"/> (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).*

**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**

|   |   |
|---|---|
| <b>Details of Proposers:</b><br>(Organisation Name)   | Intergen  |
| <b>Capacity in which the CUSC Modification Proposal is being proposed:</b><br>(i.e. CUSC Party, BSC Party or "National Consumer Council") | CUSC Party  |
| <b>Details of Proposer's Representative:</b><br>Name:<br>Organisation:<br>Telephone Number:<br>Email Address:                             | Nigel Cornwall<br>Cornwall Energy<br>01603 604406<br>nigel@cornwallenergy.com       |
| <b>Details of Representative's Alternate:</b><br>Name:<br>Organisation:<br>Telephone Number:<br>Email Address:                            | Robert Longden<br>Associate of Cornwall Energy<br>tbc<br>rcl@longdenr.wanadoo.co.uk |
| <b>Attachments (Yes/No):</b> No<br><b>If Yes, Title and No. of pages of each Attachment:</b>  |   |

## 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](mailto: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](mailto:jade.clarke@nationalgrid.com) and copied to [cusc.team@nationalgrid.com](mailto: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.

CUSC Modification Proposal Form Charging v1.6



### 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 28<sup>th</sup> 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 17<sup>th</sup> July 2014 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 25<sup>th</sup> July 2014.

### Membership

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

| Role                                 | Name            | Representing         |
|--------------------------------------|-----------------|----------------------|
| <b>Chairman</b>                      | Alex Thomason   |                      |
| <b>National Grid Representative*</b> | Tushar Singh    | National Grid        |
| <b>Industry Representatives*</b>     | 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          |
| <b>Authority Representatives</b>     | Donald Smith    | Ogfem                |
| <b>Technical secretary</b>           | Jade Clarke     |                      |
| <b>Observers</b>                     |                 |                      |

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

|                            |  |
|----------------------------|--|
| 14 <sup>th</sup> July 2014 | Deadline for comment                                 |
| 17 <sup>th</sup> July 2014 | Submit final Workgroup Report to Panel               |
| 25 <sup>th</sup> 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 |
|-----------------|----------------------|---------------------|------------|------------|------------|
| Alex Thomason   | Code Administrator   | Independent Chair   | A          | A          | O          |
| Jade Clarke     | Code Administrator   | Technical Secretary | A          | A          | A          |
| Tushar Singh    | National Grid        | Workgroup Member    | A          | A          | O          |
| Cem Suleyman    | DRAX                 | Workgroup Member    | X          | A          | A          |
| Ebba John       | Dong Energy          | Workgroup Member    | X          | A          | A          |
| Frank Prashad   | RWE NPower           | Workgroup Member    | A          | A          | X          |
| Garth Graham    | SSE                  | Workgroup Member    | A          | A          | D          |
| Guy Phillips    | EON                  | Workgroup Member    | A          | A          | A          |
| James Anderson  | Scottish Power       | Workgroup Member    | A          | A          | X          |
| Jonathan Wisdom | NPower               | Workgroup Member    | A          | A          | X          |
| Lisa Waters     | Eggborough Power Ltd | Workgroup Member    | O          | O          | O          |
| Paul Mott       | EDF                  | Workgroup Member    | A          | D          | A          |
| Robert Longden  | Intergen             | Proposer            | A          | D          | O          |
| Donald Smith    | Ofgem                | Observer            | D          | D          | A          |

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 Tariff part of the table.

CMP227 G:D Split Tariff Modelling for 2016/17

Diversity Model

| £: Euro ER  |    | G:D Split                             | 27:73 | 18.3:91.7 | 15:85 | 4.26:95.74 | 2.1:97.9 | 0:100  |
|---|----|---------------------------------------|-------|-----------|-------|------------|----------|--------|
| 1.26  |    | 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   |
| Demand Fc 16/17 TWh   |    | Amount recovered from Generation (£m) | 806   | 548       | 448   | 127        | 63       | 0      |
| 319   |    | 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<br>Zonal Tariff<br>£/kW<br><br>Includes small<br>gen tariff  | 1  | Northern Scotland                     | 15.98 | 20.66     | 22.47 | 28.28      | 29.45    | 30.58  |
|   | 2  | Southern Scotland                     | 17.10 | 21.77     | 23.59 | 29.39      | 30.56    | 31.70  |
|   | 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  |
|   | 5  | Yorkshire                             | 37.04 | 41.72     | 43.53 | 49.34      | 50.51    | 51.64  |
|   | 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<br>Zonal Tariff<br>p/kWh<br><br>Includes small<br>gen tariff  | 1  | Northern Scotland                     | 2.16  | 2.80      | 3.04  | 3.83       | 3.99     | 4.14   |
|   | 2  | Southern Scotland                     | 2.38  | 3.03      | 3.28  | 4.08       | 4.25     | 4.40   |
|   | 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   |
|   | 5  | Yorkshire                             | 5.04  | 5.67      | 5.92  | 6.71       | 6.87     | 7.02   |
|   | 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   |
| Generation<br>Zonal Tariff<br>(£/kW)<br><br>Actual tariff<br>depends on<br>plant type<br>and load<br>factor | 1  | North Scotland                        | 35.88 | 32.61     | 31.34 | 27.27      | 26.45    | 25.65  |
|   | 2  | East Aberdeenshire                    | 31.38 | 28.10     | 26.83 | 22.76      | 21.94    | 21.15  |
|   | 3  | Western Highlands                     | 34.44 | 31.17     | 29.90 | 25.83      | 25.01    | 24.21  |
|   | 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  |
|   | 6  | Central Grampian                      | 34.39 | 31.11     | 29.84 | 25.77      | 24.96    | 24.16  |
|   | 7  | Argyll                                | 33.67 | 30.40     | 29.13 | 25.06      | 24.24    | 23.44  |
|   | 8  | The Trossachs                         | 30.43 | 27.15     | 25.88 | 21.81      | 20.99    | 20.20  |
|   | 9  | Stirlingshire and Fife                | 29.06 | 25.78     | 24.51 | 20.44      | 19.62    | 18.83  |
|   | 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 |





Date: August 2014

**CMP 227 – Customer benefits**  
***A supporting paper prepared for Intergen***

Prepared by Cornwall Energy

## About Cornwall Energy

Cornwall Energy's team of independent specialists have experience of liberalised energy markets and their regulation since their inception in Great Britain and elsewhere in the late 1980s. We provide consultancy, intelligence and training, and are a trusted and reliable partner whether you are a new entrant or a large, established player.

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- regulation and public policy within both electricity and gas markets;
- electricity and gas market design, governance and business processes; and
- market entry.

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*Numbers may not add up due to rounding.*

## Control sheet

|                     |  |
|---------------------|--|
| Document author(s): |  |
| Project owner:      |  |

### Revision history

| Date           | Version No. | Summary of changes             |
|----------------|-------------|--------------------------------|
| 16 June 2014   | 1           | Content review and edit        |
| 7 July         | 2           | For issue                      |
| 04 August 2014 | 3           | Change to reflect new comments |

### Distribution

| Name                  | Job title | Date       | Version |
|-----------------------|-----------|------------|---------|
| CMP 227 working group |           | 09/07/2014 | 2       |
|                       |           |            |         |

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## I 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, CMP227 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<sup>1</sup> 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*<sup>2</sup> 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.<sup>3</sup>

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

<sup>1</sup>

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

<sup>2</sup> <https://www.ofgem.gov.uk/ofgem-publications/75232/electricity-capacity-assessment-report-2013.pdf>

<sup>3</sup> 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 I**, 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 I 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 through 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<sup>4</sup> 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), as 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<sup>5</sup> 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

<sup>4</sup> [https://www.gov.uk/government/uploads/system/uploads/attachment\\_data/file/324430/Final\\_Capacity\\_Market\\_Impact\\_Assessment.pdf](https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/324430/Final_Capacity_Market_Impact_Assessment.pdf)

<sup>5</sup> <http://www.nationalgrid.com/NR/rdonlyres/F3F35BA1-8FCA-4206-9234-85D59B2ADB66/62904/FinalProposalsConsultationDSBRSBR10thOctober2013FinalI.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<sup>6</sup>.

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<sup>7</sup> 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.<sup>8</sup>

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.

<sup>6</sup> The total costs available are capped under the Levy Control Framework.

<sup>7</sup> <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/>

<sup>8</sup> There is an interaction here with the Capacity 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 reflect 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 MWh of 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<sup>9</sup> should result in greater security of supply and result in overall lower costs while dampening wholesale price volatility.

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<sup>9</sup> 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<sup>10</sup> 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.

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