nationalgrid

Stage 02: Workgroup Consultation

Connection and Use of System Code (CUSC)

CMP268

'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits

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

CMP268 aims to change the charging methodology to more appropriately recognise that the different types of "Conventional" generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of "Conventional" generation pays. The change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator's ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements.

This document contains the discussion of the Workgroup which formed in August 2016 develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 7 of this document.

Published on: 16 September 2016
Length of Consultation: 10 Working days
Responses by: 30 September 2016

High Impact: Generation TNUoS payers.

Contents

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 CMP268 CUSC Modification Proposal which was raised by John Tindal, SSE and developed by the Workgroup. Parties are requested to respond by **5pm** on **30 September 2016** to 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/CMP268/

Document Control

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0.1	09/09/16	Code Administrator	Draft Workgroup Consultation to Industry
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Any Questions?

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1 Summary

1.1 This document describes the Original CMP268 CUSC Modification Proposal (the Proposal), summarises the deliberations of the Workgroup and sets out 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 CMP268 was proposed by SSE and was submitted to the CUSC Modifications Panel for their consideration on 27 July 2016. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the CUSC Applicable Objectives. The Authority determined that the proposal should be considered on an urgent timescale. The letter from the Authority setting out the reasons for urgency is set out in Appendix 6. The timetable for urgent consideration is set out in the Terms of Reference in Appendix 2.

1.3 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 11 October 2016 Special CUSC Panel meeting.

1.4 CMP268 aims to change the charging methodology to more appropriately recognise that the different types of “Conventional” generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of “Conventional” generation pays. The change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator’s ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements. This does not change the way the Year-Round tariff is calculated and it does not change existing generator classifications, but it does change the formula by which the Year-Round tariff is applied to different types of Conventional generator.

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/CMP268/ along with the Modification Proposal Form.

2 Background on the Proposer's view of the defect

2.1 The modification proposal set out the proposer's views on the nature of the defect and the potential solution. Note that this section is representative of the Proposers view and is not a view that is wholly supported by Workgroup members. Counter arguments to these views can be found in Section 3 of this Consultation in the Workgroup discussion.

Context of the CMP268 Original proposal

2.2 Prior to 1 April 2016, the TNUoS charging methodology applied the same TNUoS tariff formula to all classes of generator based on 100% of their Transmission Entry Capacity (TEC). The Authority considered that there may be an opportunity to improve the cost reflectivity of the charging methodology, therefore on 25 May 2012, the Authority directed NGET[1] to raise a Modification proposal to the CUSC to ensure that it better reflects the costs imposed by different types of generators on the electricity transmission network (a.k.a. network **sharing**). This direction also related to the treatment of **High Voltage Direct Current** (HVDC) circuits and **island connections**).

2.3 It followed that the CMP213 CUSC Modification Proposal was submitted to the CUSC Modifications Panel (the Panel) for their consideration on 29 June 2012 which proposed changes including the creation of two different backgrounds within the ICRP Transport model (Peak Security and Year-Round), and an associated new TNUoS tariff formula consisting of a Peak Security tariff element (paid by all generators except those classed as intermittent) and a Year-Round tariff element paid by all generators. CMP213 Original also proposed that for each generator, the Year-Round tariff element should be adjusted by being multiplied by each generator's Annual Load Factor (ALF) to better reflect the network investment cost which they cause according to the Economy Criteria of the NETS SQSS and also better reflect a full Cost Benefit Analysis (CBA). During the CMP213 Workgroup process, many different alternatives to this approach were considered including the alternative which became defined by Workgroup Alternative Modification Proposal 2 (WACM2).

2.4 WACM2 proposed that the charging methodology could be even more cost reflective if it took account of the degree of diversity behind a network boundary. This was based on the reasoning that when the network flows on a particular circuit are dominated by generators who are very expensive to constrain off (due to high negative bid prices), then those generators will tend to cause a level of required network investment of those affected circuit at a level closer to 100% of their TEC instead of proportional to their ALF. The Proposer noted that the economic rationale was that even if those expensive bid price stations were involved in a relatively small volume of network constraints, then the high cost of constraining them off would mean that it may tend to be more economically viable to invest in sufficient transmission network capacity such that those stations with expensive bid prices would need to be constrained off rarely, or not at all in order to manage network constraints.

2.5 On 25 July 2014, the Authority considered the selection of alternative proposals which were presented to it and decided to approve WACM2 with an implementation date of April 2016. This decision was challenged through a Judicial Review, then on 23 July

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

2015, the Judgement was handed down that The Authority's decision was correct as per the following extract from the conclusion of the judgement:

2.5.1 "[64.] The decision of the Authority to approve the modification known as WACM 2 to the charging methodology relating to the recovery of costs incurred in connection with investment in the transmission system for electricity is lawful. **The decision establishes a charging methodology which reflects** the impact that different classes of generators are anticipated to have on investment costs in terms of providing the infrastructure necessary to ensure demand at peak times is met and, **broadly, the impact that particular generators have on investment decisions taken to address constraints within the system**."[2]

2.6 The Proposer supports the Authority's decision to implement WACM2 and supports the Judicial Review Judgement that WACM2 does broadly reflect the "…impact that particular generators have on investment decisions taken to address constraints within the system." However, the proposer also notes that it remains possible to develop additional proposals to even further improve on the cost reflectivity of the charging methodology. To this end CMP268 Original proposal further improves the charging methodology as introduced by CMP213 WACM2 to even further improve its cost reflectivity with regard to the way the cost of constraints is reflected in respect to a particular special set of circumstances.

2.7 CMP268 Original proposal does not seek to change the ICRP Transport model, or the way the Year-Round tariff is calculated, therefore the set of locational tariffs produced by the Transport model are not affected. This Original proposal does not seek to change existing generator classifications as already defined within the charging methodology. This proposal also does not seek to change the methodology used to calculate diversity, or how this relates to the charges paid by Low Carbon, or Intermittent generators.

2.8 The only aspect which this Original proposal does seek to change is with regard to the tariff formula by which the existing Year-Round Not-Shared tariff element is applied to only the specific type of individual generator which the charging methodology currently defines as being classed simultaneously as both "Conventional" and "Carbon".

Proposer's description of the defect

2.9 The Proposer considers the current charging methodology fails to adequately reflect the fact that when the flows behind a boundary are dominated by low carbon generation, then different types of "Conventional" generation (e.g. low load factor peaking plant compared with higher load factor CCGTs, or Nuclear) cause different transmission network investment costs to be incurred due to their different network sharing characteristics.

2.10 The defect identified by this modification proposal relates to a type of generating plant which the existing charging methodology defines as being both "Conventional" and "Carbon". For the purpose of simplicity, this modification proposal refers to this group of generators as "Conventional Carbon". To aid understanding of the modification proposal, an explanation is provided in the section below and this "Conventional Carbon" generator type is highlighted in red in Table 1 below

[2] CMP213 Judgement

2.11 In the Proposer's view the defect is that there is a specific circumstance where the charging methodology is not cost reflective because it fails to recognise that Conventional Carbon plant does in fact continue to fully share all Year-Round circuit costs even in circumstances when the proportion of plant which is Low Carbon exceeds 50%. This is because Conventional Carbon generators tend to provide positive bid prices, so continue to provide a relatively low cost option for managing constraints irrespective of the concentration of low carbon generation behind a boundary.

2.12 The Proposer notes the defect in the current methodology delivers the result that "Conventional Carbon" plant in zones with a significant Not-Shared Year-Round tariff are charged TNUoS tariffs which are higher than the cost they cause and therefore the charging methodology is not cost-reflective in those specific circumstance for that type of plant.

2.13 The Proposer also considers within the current methodology, when the penetration of Low Carbon generators increases beyond 50%, the degree of sharing of Year-Round circuits is assumed to linearly reduce for all classes of generation. The current methodology therefore applies the TNUoS tariff elements to all "Conventional" generators in the same way irrespective of whether they are classed as "Carbon" (low constraint cost impact due to low BM bid cost), or "Low Carbon" (High constraint cost impact due to high BM bid cost). In the view of the Proposer this represents a defect because the ability of Conventional Carbon to share with Low Carbon plant actually <u>increases</u> as Low Carbon plant becomes more dominant. The existing charging methodology assumes exactly the opposite relationship and therefore provides incorrect and perverse locational incentives for Conventional Carbon generators within zones with a relatively high concentration of Low Carbon generators.

<u>Explaining the Status Quo on the Classifications of Generators.</u>

2.14 The Proposer notes that to understand this modification proposal, it is important to be clear regarding the following terms which have a specific technical definition within the existing charging methodology:

2.14.1 **Technology type by dispatchability:** Two classes of either "conventional" or "intermittent" depending on whether they can be dispatched as firm, or non-firm respectively.

2.14.2 **Technology type by bid price:** Two classes of either "carbon" or "low carbon" depending on whether they tend to exhibit low cost, or high cost balancing mechanism bid prices respectively due to their short-run marginal cost of generation.

2.15 The Proposer also notes that these two different sets each containing two different technology classes effectively combined to produce four different classification types. These four different types were created by CMP213 to enable TNUoS charges to better reflect the different costs to transmission network investment caused by different types of generator. The first classification type of "Conventional" versus "Intermittent" is used by the charging methodology to identify whether a generator can be dispatched on a firm basis, so identify whether or not it pays the Peak Security tariff element. The second classification type of "Carbon" versus "Low Carbon" is used by the charging methodology to adjust the degree of sharing by taking account of the level of diversity as defined by the concentration of "Low Carbon" generation. The table below describes the four potential plant classification combinations and also includes a list of which generation technology types are currently included within each category by the existing charging methodology:

		Technology type by bid price	
		"Carbon" (Assumed low cost BM bid price)	**"Low carbon"** (Assumed high cost BM bid price)
Technology type by dispatchability	**"Conventional"** (Firm dispatch, so pays Peak Security tariff)	**"Conventional Carbon":** CCGT, OCGT, Coal, pumped storage, CHP, biomass	**"Conventional Low Carbon":** Nuclear, hydro
	"Intermittent" (Not firm dispatch, so does not pay Peak Security tariff)	**"Intermittent Carbon"**: No technologies identified	**"Intermittent Low Carbon"**: Wind, PV, tidal, wave

Table 1: Technology type – dispatchability by bid price

2.16 Further detail regarding these four existing classification types is described below

2.16.1 Characterisation by dispatchability

- **"Conventional"** – Stations which are capable of dispatching on a firm basis to meet peak demand. These stations contribute to network flows within the ICRP Transport model Peak Security background, so these stations pay the Peak Security tariff element.

- **"Intermittent"** - Stations which are not capable of dispatching on a firm basis to meet peak demand because they are reliant on a weather dependent source of input energy. These stations do not contribute to network flows within the ICRP Transport model Peak Security background, so these stations do not pay the Peak Security tariff element.

2.16.2 Characterisation by bid price

- **"Carbon"** – This is the name used (for the purpose of CMP213) to identify a class of generating stations that comprises generation plant that is flexible in nature, can reduce/increase output driven by market price and transmission system needs and importantly has a material positive short run marginal cost. In practice all interconnectors and all transmission-connected storage are allocated by CMP213 into this category. This plant type will tend to bid to the System Operator in the Balancing Mechanism to reduce production at a relatively low cost (positive bid price), so offering a relatively low cost solution to managing constraints.

- **"Low carbon"** - This is the name used (for the purpose of CMP213) to identify a class of generating stations with the purpose of including stations which tend to operate on a "must run" basis, so almost always generate when input energy is available or, for technical reasons are inflexible, irrespective of transmission system need; e.g. demand level. This plant type will tend to bid to the System Operator in the Balancing Mechanism to reduce production at a relatively high cost (low or negative bid price), so offering a relatively high cost solution to managing constraints.

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

Table 13 – Classifications used for carbon vs. low carbon

Table 2: Classification used for carbon vs low carbon generation taken from CMP213 FMR

Baseline

2.17 Transmission licensees – both onshore and offshore – are required by their licences to comply with the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS)[3], which sets out criteria and methodologies for planning and operating the GB Transmission System. This cost is then reflected by the TNUoS tariffs calculated according to the Investment Cost Reflective Pricing (ICRP) methodology using the Direct Current Load Flow (DCLF) Transport model. The SQSS was changed in 2011 to include the locational elements of the Security Background and the Economy Background. Then project TransmiT resulted in Ofgem reaching a decision regarding CMP213 which introduced changes to the ICRP charging methodology to reflect the new SQSS investment criteria by introducing the locational Peak Security tariff element and the locational Year-Round tariff elements.

Economic case for the Principle of the "ALF"

2.18 The Proposer provided extracts from the CMP213 Original proposal which he considered explained the economic rational regarding why it is cost reflective for TNUoS charges to reflect incremental constraint cost.

2.18.1 "As a greater proportion of variable, renewable generation connects to the transmission network, the output of many conventional generators has also

[3] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/The-SQSS/

become more variable in nature. As generators of different types change the way in which they use the transmission network, the nature of transmission capacity investment planning has also altered to ensure efficient investment is undertaken. **This is exemplified in the recent changes to the NETS SQSS (GSR-009) and the increasing amount of investment justified on the basis of avoided future constraint costs** (i.e. outside of the deterministic NETS SQSS standards). In order to maintain a consistent level of cost reflectivity, Transmission Network Use of System charges must also evolve to reflect these underlying physical changes."[4]

2.19 The Proposer noted the requirement within the NETS SQSS for the Main Interconnected Transmission System (MITS) to meet the Economy Criteria is described below:

2.19.1 "The *MITS* shall meet the criteria set out in paragraphs 4.5 to 4.6 under both the Security and **Economy background** conditions"[5]

2.20 The Proposer highlighted the Authority Decision regarding GSR009[6] which he considers explains the economic reason for the introduction of the Economy Criterion into the NETS SQSS as described below:

2.20.1 "GSR009 proposes a 'dual criteria' approach to assessing required capacity which would take into account both demand security and economic efficiency when developing the transmission network.

2.20.2 "An Economy Criterion which requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The approach involves a set of deterministic parameters which have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an **appropriate balance between the constraint costs and the costs of transmission reinforcements.** The assumptions in the generic or pseudo CBA would be reviewed every five years."

2.21 The Proposer highlighted that the CMP213 Original proposal went on to explain why the inclusion of an Annual Load Factor (ALF) to the TNUoS charging formula would result in TNUoS charges which are more cost reflective:

2.21.1 "Explicit commercial arrangements are not in place that provide Transmission Licensees with information to assess the impact on the need for transmission network investment arising from an individual generator when planning investment. Therefore implicit assumptions over input prices (fuel, CO2, subsidy, etc.) and generator characteristics (efficiency, availability, etc.) relative to the remainder of the market are made. In order to remain cost-reflective, any proposed scaling factor needs to be reflective of the implicit assumptions made

[4] **CMP213 Original CUSC Modification Proposal "Project TransmiT TNUoS Developments" (National Grid, 20/06/2012).** http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

[5] NETS Security and Quality of Supply Standard Issue 2.2 – 5 March 2012 - Current. http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/The-SQSS/

[6] National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS): Minimum transmission capacity requirements (GSR009). http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/Modifications/Concluded/

when planning network capacity. **This proposal puts forward a form of generator specific annual load factor, based on 5 years historic output, as representative of the assumptions made when planning investment and achieving an appropriate balance between simplicity and cost-reflectivity In order to maintain what is deemed to be an appropriate balance it is proposed that the annual load factor be applied in an equal manner across all wider TNUoS zones regardless of generation plant mix**

2.22 The Proposer noted the Authority decision[7] regarding CMP213 was to implement the Workgroup Alternative Modification Proposal 2 (WACM2).

2.22.1 "Following careful consideration of the evidence, including all the consultation responses, we find that our minded-to option set out in August 2013 and April 2014 is **more cost reflective than the current methodology and best meets our statutory duties**. We have therefore decided to approve this option for implementation in April 2016. We announced our decision on 11 July 2014 and this document sets out our reasoning."

2.23 The Proposer highlighted that there would also be two further adjustments to the Year-Round tariff. The first of these is to split the tariff into two elements: 'shared' and 'non-shared.' This refers to generators' ability to 'share' transmission capacity which depends on the concentration of types of generators in a particular area. It recognises that it is efficient to build more transmission capacity for areas with a high concentration of low carbon generation because **this type of plant** is likely to be generating at the same time (i.e. when the wind blows) and **is expensive to constrain off**.

2.24 The second adjustment is to adjust the 'shared' element of the Year-Round tariff by a generator's average annual load factor for the last five years (with the highest and lowest years discarded). **This recognises that there is a link between the level of constraint costs triggered by a generator and the level of transmission investment**.

The element of the current tariff formula CMP268 proposes to change

2.25 The Proposer noted when the percentage of low carbon plant behind a boundary increases above 50%, the current methodology assumes a straight line reduction in the degree of sharing from 50% until the proportion of load flow on the circuit accounted for "Carbon" plant declines to 0%. This is illustrated in the graph below.

[7] Project TransmiT: Decision on proposals to change the electricity transmission charging Methodology, Ofgem 25 July 2014. http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

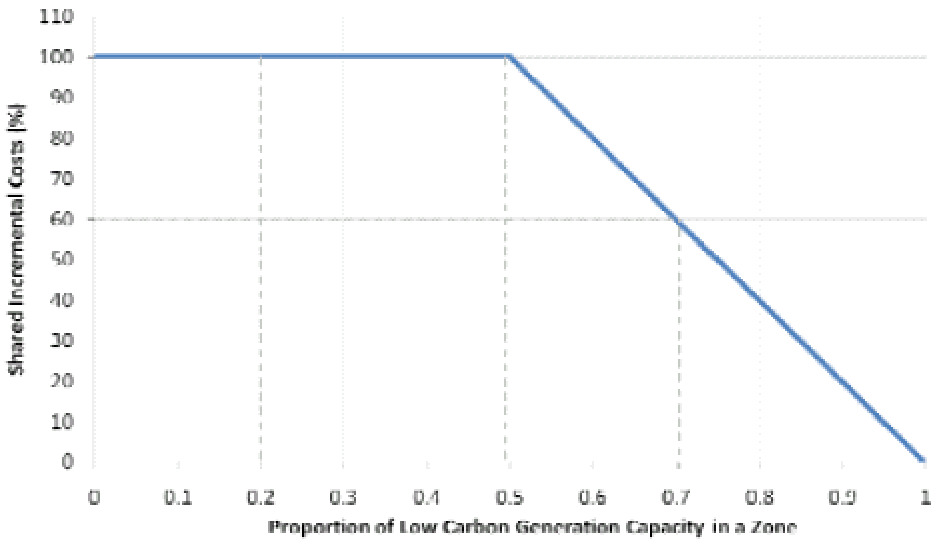


Figure 1: Taken from "Figure 18" from the CMP213 Workgroup Final report.

2.26 The Proposer highlighted that this principle is enacted through the current formula within the charging methodology where all generators (including Conventional Carbon generators) have their ALF applied to their Shared Year-Round tariff element, while also for <u>all types of generator</u>, their ALF is not applied to their Not-Shared Year-Round tariff element. This is illustrated for Conventional Generators by the formula below in Figure 2 taken from National Grid published Final TNUoS tariffs for 2016/17.

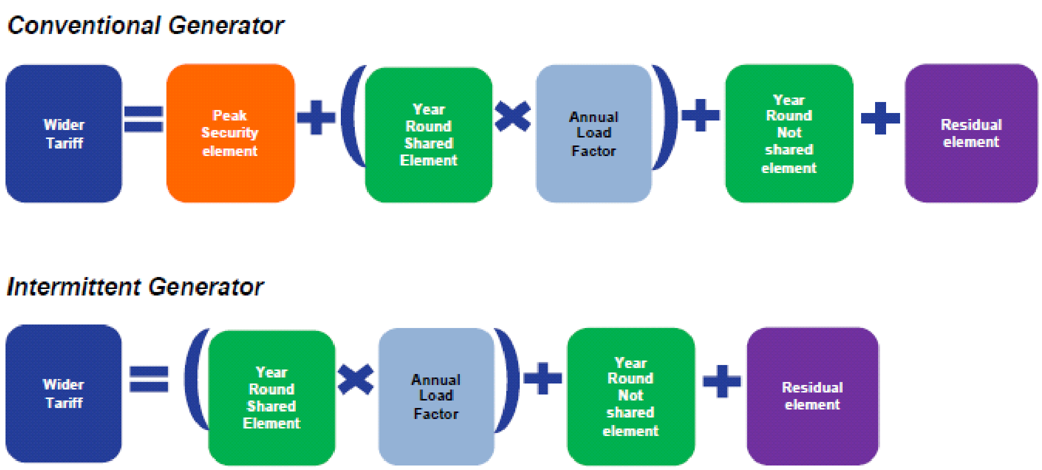


Figure 2: Charging Methodology

<u>**Purpose of the proposal**</u>

2.27 The Proposal is that the charging methodology should be changed to more appropriately recognise that the different types of "Conventional" generation (those classed as "carbon" compared with those classed as "low carbon") do cause different transmission network investment costs, which should be reflected in the TNUoS charges that these different types of "Conventional" generation pays.

2.28 The Proposer asserts that change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator's ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements.

<u>Proposed change to TNUoS tariff formula</u>

2.29 The Proposer states this modification proposes a change to the tariff formula relating to the way sharing is applied to Conventional Carbon generators so they continue to obtain 100% sharing of incremental costs irrespective of the proportion of low carbon generation capacity in a zone. This is illustrated by the graph below, which is a modified version of "Figure 1" above.

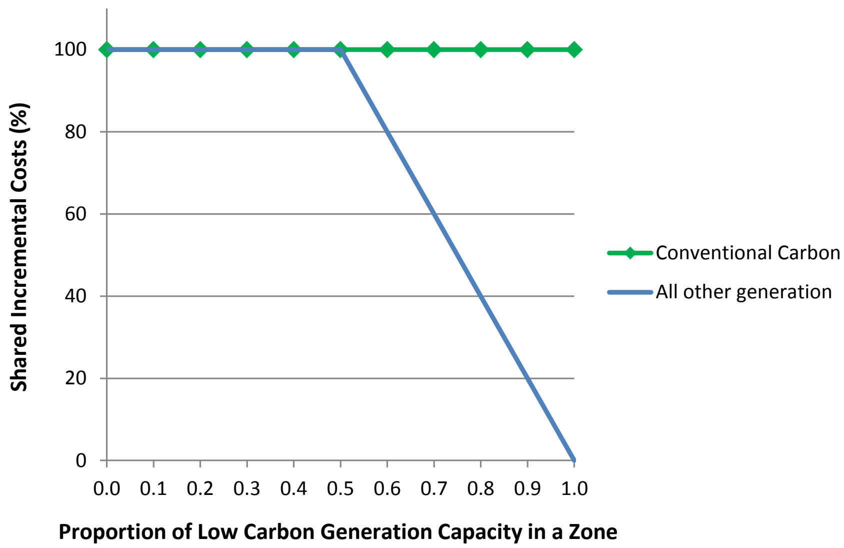
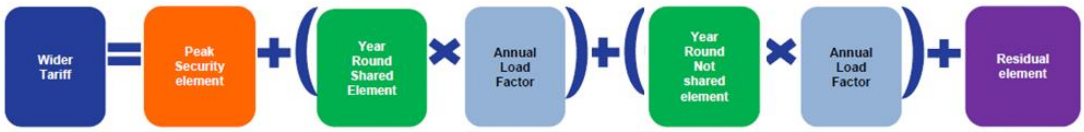


Figure 3: Proposed change - Modified Figure 1

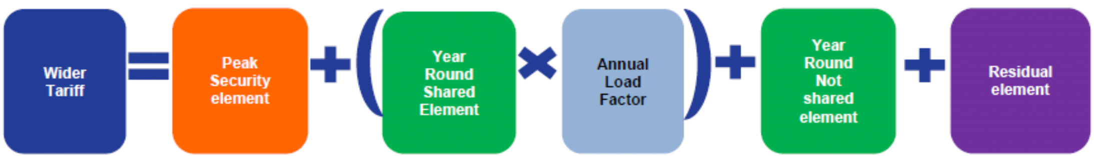
2.30 The Proposer highlights that this modification proposal will recognise that even when the proportion of “Low Carbon” plant influencing a boundary is close to 100%, then it is more cost reflective that conventional carbon plant should have its ALF applied to the whole Year-Round tariff (both Shared and Not-Shared elements of Year-Round).

2.31 The Proposer states that this will require a change to the existing tariff formula which currently relates to “Conventional Generator” by splitting it into two: firstly the new tariff formula relating to “Conventional Generator – Carbon” and secondly unchanged existing tariff formula which will continue to apply to “Conventional Generator - Low Carbon”. For the avoidance of doubt, the existing tariff formula relating to “Intermittent Generator” is also unchanged by this modification proposal. The proposed new tariff calculation formulas are illustrated below:

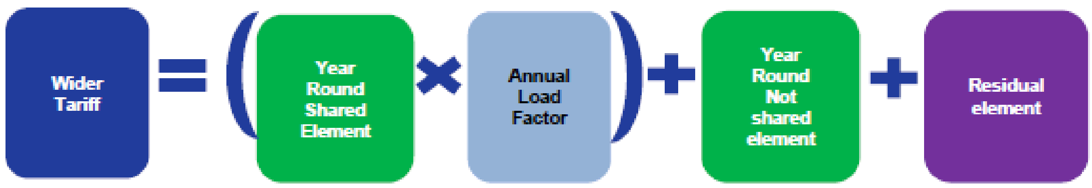
2.31.1 ***Adjusted tariff formula: “Conventional Generator – Carbon”*** - This represents a change from the existing “Conventional Generator” tariff formula since it applies the Generator’s ALF to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements.



2.31.2 ***Unchanged tariff formula: “Conventional Generator – Low carbon” -*** The tariff calculation remains the same as the current “Conventional Generator” tariff. It would be appropriate to give this unchanged tariff formula a new name to ensure it is clear which types of generation this applies to.



2.31.3 ***Unchanged tariff formula: “Intermittent” -*** For the avoidance of doubt, the tariff formula currently used by the baseline for “Intermittent” generators is not affected by this modification proposal and remains unchanged as per the formula below.



2.32 It is proposed that this new tariff calculation methodology would apply from the TNUoS charging year starting April 2017.

3 The Proposers Presentation

Economic rationale behind network sharing

3.1 The proposer presented extracts from the CMP213 Final Workgroup Report Sections 4.19 to 4.20 in which the report explained a key principles which determine the degree of sharing including:

"The [CMP213] Workgroup agreed that annual incremental constraint costs for each generator with a given TEC (i.e. £/MW/annum) are comprised of two main components, illustrated below in Figure 5 which could be further sub-divided into five variables." (CMP213 Final Workgroup Report 4.19)

The proposer presented the following figure which the CMP213 Final Workgroup report used to illustrate this principle:

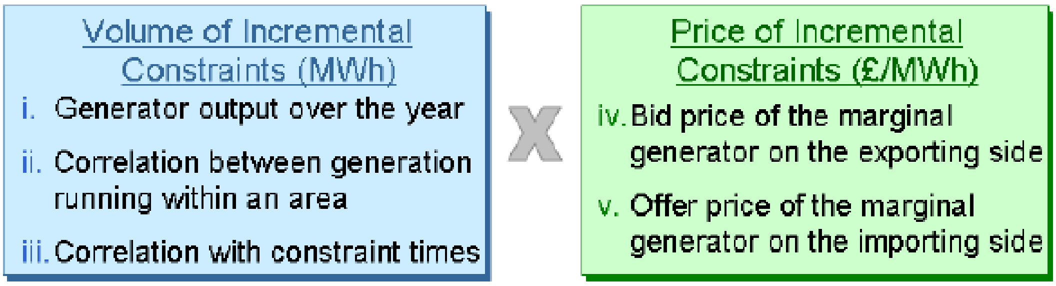


Figure 5 – Components that drive transmission constraint costs

3.2 The proposer presented the case that these are the key principles regarding why a Conventional Carbon generator is able to fully share all Year Round circuits irrespective of the penetration of low carbon plant behind a network boundary. The proposer suggested these principles are consistent with the greater detail regarding sharing which can be found in the CMP213 Final Workgroup Report Volume 2, Annex 4, Sharing.

3.3 The proposer explained these factors in the context of an OCGT as an example of a carbon emitting low load factor peaking plant in the following way.:

- **Generator output over the year** – The proposer suggested that if a generator does not generate at all, then it does not cause any change in Year Round circuit flows so it does cause any change in the required investment in transmission network required to manage constraints. A higher penetration (e.g. greater than 50%) of low carbon generation in an area does not change this relationship.

- **Correlation between generation running in an area – The proposer suggested that a**n OCGT will tend to only dispatch in periods when wholesale power prices are relatively high, which will also tend to be correlated with periods when generation from low carbon plant is relatively low, therefore their generation will tend to be counter correlated. A third variable can affect this correlation such as cold wintery weather because the associated high demand conditions may enable conventional carbon to generate to earn high wholesale power prices at the same time as relatively high wind conditions without causing constraints. A higher penetration (e.g. greater than 50%) of low carbon generation in an area does not change this relationship.

- **Correlation with constraint times –** The proposer suggested that is the most important of the three volume related criteria. An OCGT is unlikely to be generating during periods when constraints occur. This is because periods of constraint tend to be associated with periods of relatively high output from low carbon generation occurring simultaneously with relatively low levels of demand. Therefore constraints are most likely to occur during periods of relatively low wholesale power prices during which it is highly unlikely that an OCGT would choose to be generating. A higher penetration (e.g. greater than 50%) of low carbon generation in an area does not change this relationship.

- **Bid price of the marginal generator of the exporting side –** The proposer suggested that Conventional generation is low cost to bid off to manage constraints because they have a substantial positive avoidable cost. A higher penetration (beyond 50%) of low carbon generation in an area does not change this relationship.

- **Offer price of the marginal generator on the importing side –** The proposer suggested that the short run avoidable cost of conventional carbon generators is driven by their cost of fuel which is similar for different stations of the same type. This means that that there is a relatively low cost to the SO of managing constraints by bidding off one carbon emitting generator and replacing it with a different carbon emitting generator. The proposer suggested that a higher penetration (e.g. greater than 50%) of low carbon generation in an area does not change this effect because the cost to the SO of managing a constraint by bidding off conventional carbon plant is entirely independent of whatever bid prices low carbon generators in the same area may exhibit.

Evidence – Additional analysis presented in the CMP213 Final Workgroup Report Volume 2 Annex

3.4 The proposer presented evidence extracted from the CMP213 Final Workgroup Report Volume 2 Annex sections 4.14 to 4.26. This evidence includes the results of market modelling by National Grid using the ELSI model which the proposer suggested appears to indicate that when sharing occurs, the incremental cost can be reflected a generator's ALF.

3.5 The proposer suggested that Conventional Carbon generators do continue to share even with a high proportion of low carbon generation (50% to 100% low carbon), so the network investment cost caused by Conventional Carbon generators should continue to be reflected by the "theoretical perfect relationship" as reflected by the current methodology through the use of the ALF.

Results from this ELSI model analysis which were presented to the Workgroup are illustrated with the figures below.

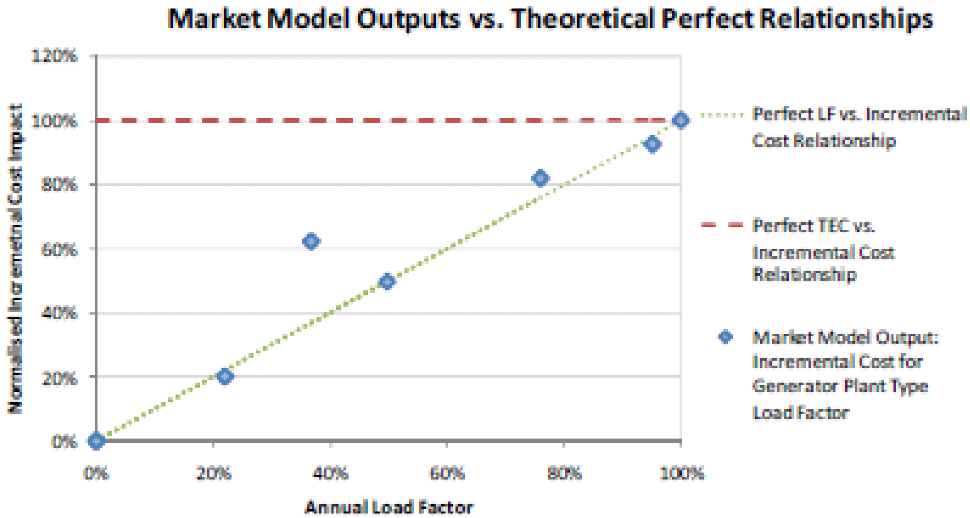


Figure 1 – Market Model Outputs vs. Theoretical Perfect Relationships

The CMP213 workgroup carried out additional analysis using the ELSI model and the following figure was included in the CMP213 Final Workgroup Report Volume 2 Annex.

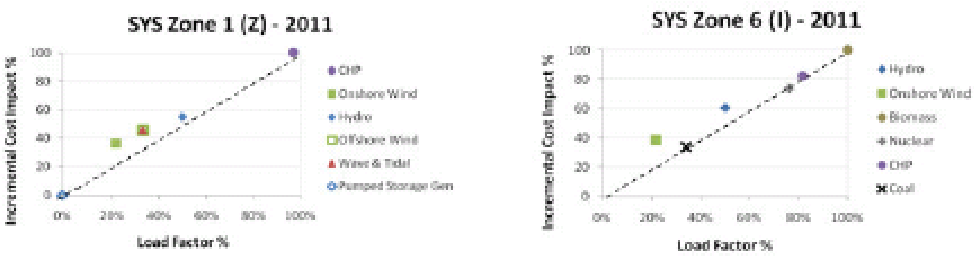


Figure 2 – Example ELSI analysis

Circumstances where sharing is reduced

3.6 The proposer described an extract from the CMP213 Final Workgroup Report Volume 2 Annex (4.111 to 4.118) which describes the potential causes which may cause sharing to break down.

3.7 The proposer interpreted this section of the CMP213 Workgroup Report as describing that as long as conventional carbon generation is available for the SO to constrain off, then sharing will continue to take place, while by contrast, sharing only breaks down when conventional carbon generation is no longer available. The proposer suggested that it logically follows that conventional carbon generators do not cause any reduction in sharing, but instead it is the absence of conventional Carbon generation which causes the reduction in sharing.

3.8 The proposer suggested that core principle of cost reflectivity is that generators should be exposed to price signals which reflect the cost that they cause. It follows that because conventional carbon generators do not cause sharing to break down, it is not cost reflective to charge them as if they do. Therefore, while it may be appropriate to charge the Not Shared Year Round tariff element at 100% of TEC to Low Carbon generators (on the reasoning that they do cause sharing to break down), it is not appropriate to charge the Not Shared Year Round element of the tariff at 100% of TEC to Conventional Carbon generators because they do not cause sharing to break down. The commentary I the CMP213 Workgroup Report Volume 2 Annex 4.118 explained that this illustrated the principle that the incremental constraint cost caused by Conventional Carbon generators remained reflected by the “theoretically perfect” red dotted line even if the penetration of Low Carbon generation exceeded 50%.

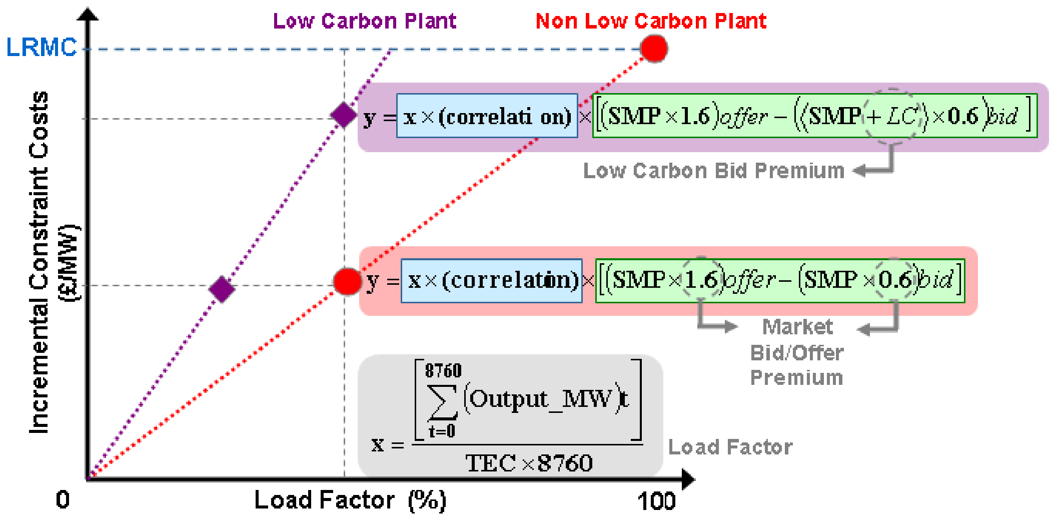


Figure 21 – Combined effect of price and load factor on constraint costs

<u>**Evidence – Simplified two node model**</u>

3.9 **Simplified two node model appears to indicate that that when sharing breaks down, it applies differently to different types of generator**

The proposer presented to the CMP213 Workgroup which used a simplified two node model to illustrate sharing. The proposer interpreted the CMP213 Workgroup report as representing evidence that Carbon plant continues to share network costs even in circumstances where Low Carbon plant may not. Therefore in circumstances when sharing breaks down, it should apply differently to different types of generator

3.10 The graph below is a result of this simplified two node economic model. The red dotted line was described as being consistent with full sharing, therefore circumstances where it is appropriate to apply the station's ALF to their Year Round tariff. The example described that further the penetration of low carbon extended beyond 50%, then the incremental cost of constraints becomes increasingly different between low carbon and carbon generation. The proposer interpreted that the analysis showed that higher penetrations of low carbon are associated with progressively lower cost of constraints caused by conventional carbon and conversely it is only the low carbon generation which is causing the higher cost of constraints.

3.11 The proposer suggested that this result would imply that it would be more cost reflective for the Year Round TNUoS charge paid by Conventional Carbon generators to become progressively lower as the penetration of wind increases. By contrast, the existing CMP213 WACM2 methodology provides the opposite result by applying progressively higher by charging 100% of TEC on the Not Shared Year Round tariff as if the Carbon generation was causing a reduction in sharing.

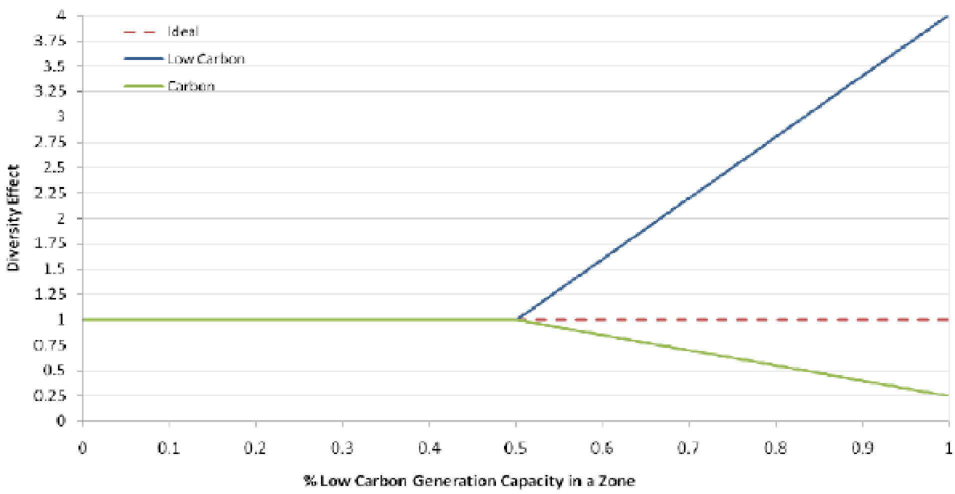


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

<u>Evidence – Simplified two node model</u>

3.12 The proposer presented a summary of evidence from ELSI modelling carried out by National Grid and previously presented to the CMP213 Workgroup.

3.13 The proposer suggested that this ELSI analysis further demonstrated that Conventional Carbon plant in SYS Zone 1 (Z) continue to fully share Year Round circuits even when flows behind a boundary are dominated by Low Carbon generation. The graphs above appear to demonstrate that when moving from a 2011 scenario to a 2020 scenario for SYS Zone 1 (Z), plant which the methodology defines as Conventional Carbon (in this example pumped storage generation and CHP) remain close to the idealized 100% sharing line in both 2011 and 2020. This means that these types of generators continue to fully share the year round circuits, so the constraint cost, therefore network investment cost which they cause continues to be proportional to their ALF even as the penetration of wind increases.

3.14 Further to this, the proposer suggested that the analysis also shows that CHP demonstrates a reduction in its incremental cost impact as it moves from above the idealised line in 2011 to below the idealised line following the increase in low carbon generation in 2020. The proposer suggested this further supports the position that as more wind is added to the system; the sharing benefit of the CHP has improved, not become worse.

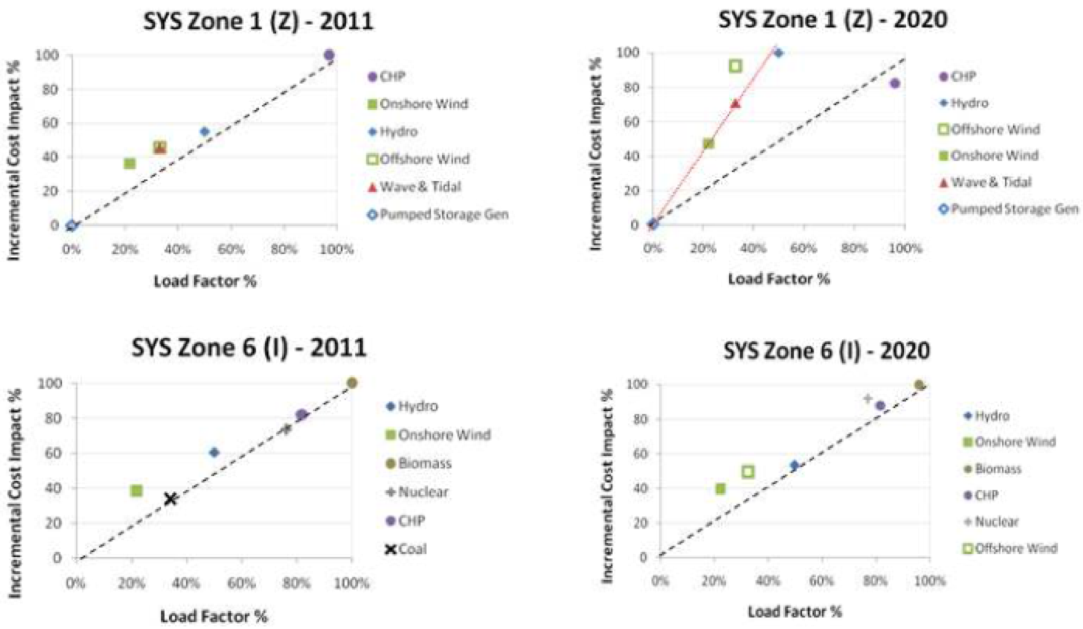
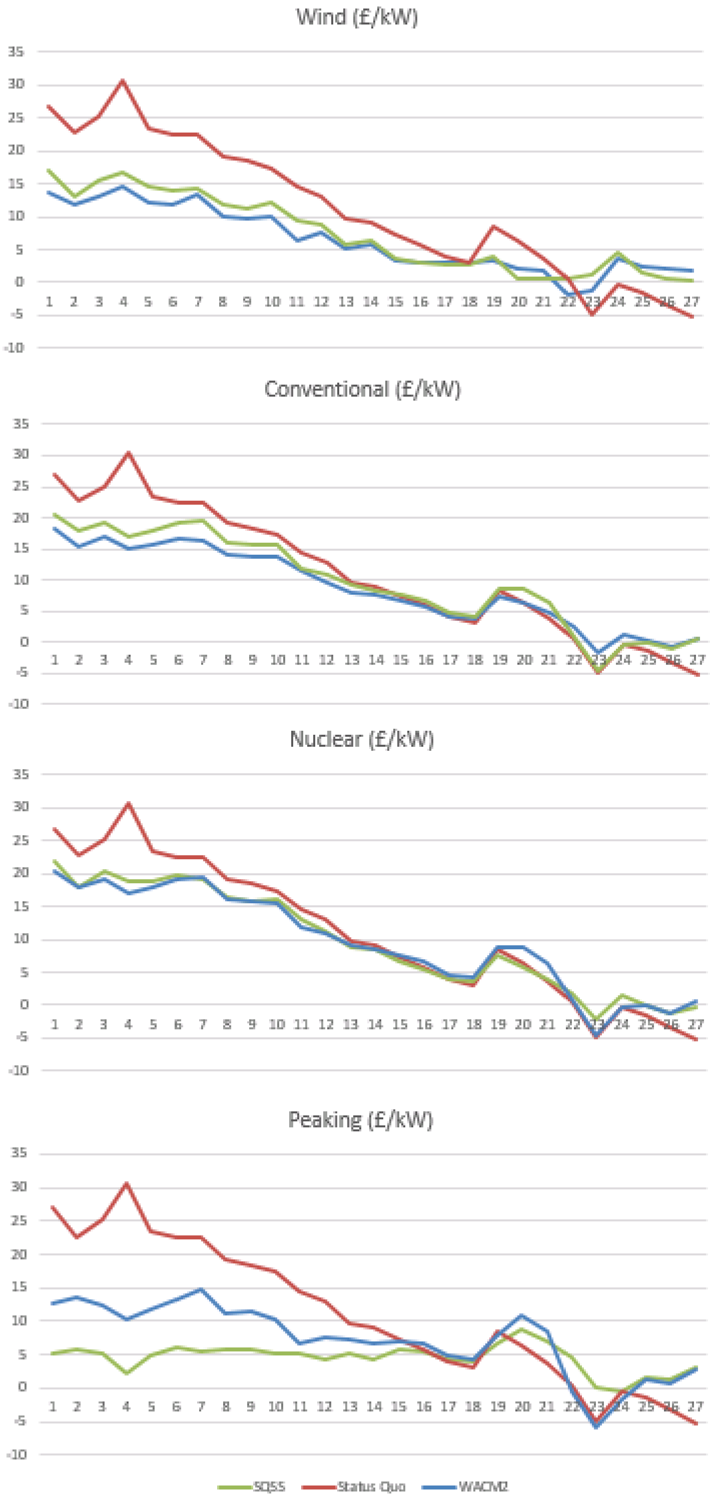


Figure 27 – Long term deterioration of the Load Factor vs. Incremental Constraint Cost relationship

<u>**Evidence Cost reflectivity compared with SQSS**</u>

3.15 The proposer presented a comparison of TNUoS charges compared with SQSS which was carried our by P E Baker. The proposer explained that this evidence can be interpreted as demonstrating CMP213 WACM2 may be over charging Conventional Carbon generators located in zones dominated by low carbon generation.

3.16 P E Baker published a report procured by SSE which carried out a comparison of [CMP213] WACM2 and Status Quo zonal charges in how they differ from costs implied by the SQSS.[8] The results of this are illustrated in the graphs below.



3.17 The proposer suggested that the following conclusions can be drawn from this analysis for different types of generator. The analysis appears to show that the CMP213 WACM2 is cost reflective of the SQSS scaling factors for most types of generator in most circumstances with the exception of low load factor Conventional Carbon plant in zones dominated by Low Carbon generation. Compared with the charges indicated by the SQSS, CMP213 WACM2 appears to charge too much to peaking plant with positive Year Round Not Shared tariffs in Scotland while it appears to charge too little for peaking plant in specific southern zones where there is a negative Not Shared Year Round tariff. The proposer suggested that these isolated examples where CMP213 WACM2 charges are furthest from being cost reflective of the SQSS are the particular examples where this CMP268 would result in an improvement in cost reflectivity so that TNUoS charges better reflected the SQSS.

<u>Alternative modelling of cost reflectivity</u>

3.18 The proposer presented simplified two node model produced by P E Baker suggesting that CMP213 WACM2 may be over charging Conventional Carbon generators located in zones dominated by low carbon generation.

The proposer suggested that this analysis demonstrated that as the penetration of wind increases, the ability of Conventional Carbon generation to share with wind increase therefore the investment cost caused by that Conventional Carbon plant reduces as illustrated by the downward sloping solid blue line in the graph above. The proposer suggested that this further supports the position that it is not cost reflective for the CMP213 WACM2 methodology to apply increasingly higher tariffs TNUoS tariffs for Conventional Carbon generators when the penetration of wind increases.

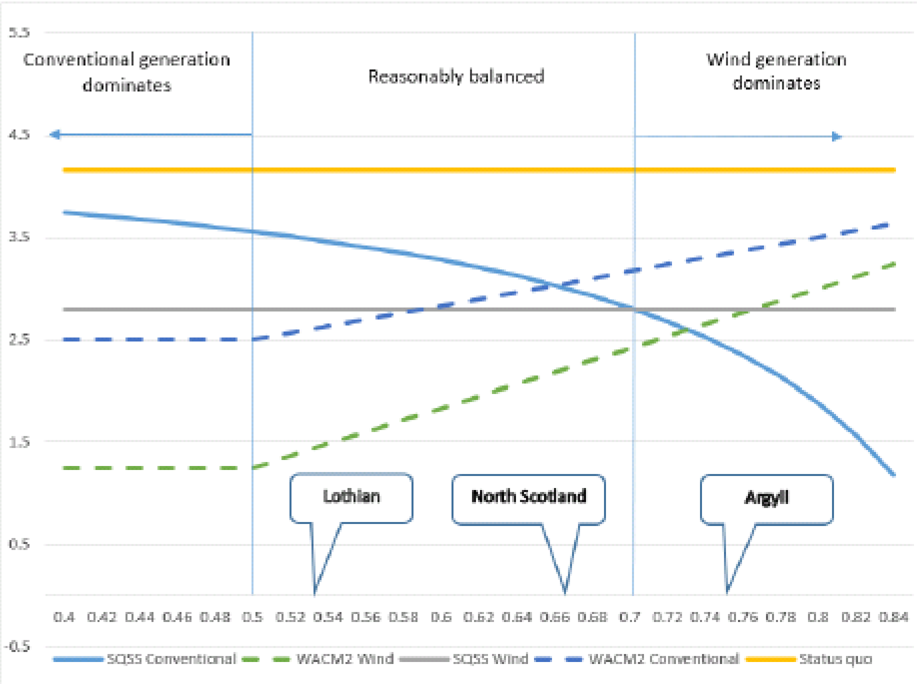


Figure 4. Variation of SQSS costs (£/kW) and WACM2 & Status Quo charges (£/kW) with sharing

Evidence from NERA/Imperial for RWE – Cost reflectivity Vs LRMC

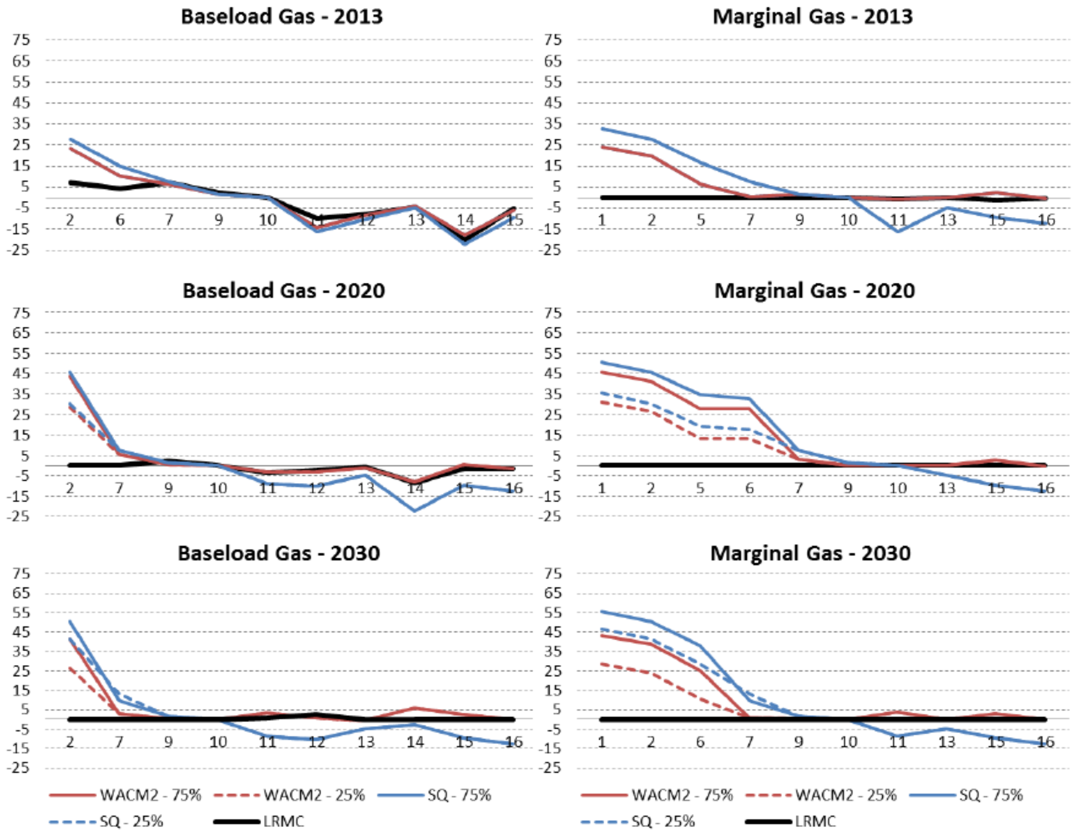
3.19 The proposer presented evidence showing a comparison with Long-run marginal cost modelling produced by NEAR/Imperial suggesting that CMP213 WACM2 may be over charging Conventional Carbon generators located in zones dominated by low carbon generation.

3.20 The proposer described that RWE procured analysis from NERA/ICL, resulting in the report Assessing the Cost Reflectivity of Alternative TNUoS Methodologies (February 2014)[9] which compared the TNUoS tariffs derived from the pre April 2016 Status Quo charging methodology and those provided by the CMP213 WACM2 methodology with an analysis of Long Run Marginal Cost (LRMC) caused by different types of generating station.

3.21 The proposer highlighted that they viewed there were many shortcomings with the approach taken by this NERA/Imperial analysis. However this report did appear to further support the proposer's position that the CMP213 WACM2 is cost reflective for most types of generator in most locations with the particular exception of Conventional Carbon plant in zones dominated by Low Carbon generators. The proposer further emphasized that the CMP268 proposal would enable the TNUoS charging methodology to improve its cost reflectivity in those specific cases, while maintaining the existing cost reflectivity for other types of generator in other locations unchanged.

3.22 The proposer presented a summary of the analysis as represented by the graphs below.

Figure 5.4
TNUoS vs. LRMC for Gas Capacity (£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

Evidence from Poyry for Centrica

3.23 The proposer presented an extract from a report produced by Poyry regarding specific circumstances where CMP213 may provide a perverse price signal which could put regional security of supply at risk. The proposer presented the quote from Poyry as follows:

> "Consider a two zone system, there the smaller zone, A consists almost entirely of wind capacity – say 9.5GW of wind and 0.5GW of inefficient OCGT (a small bit of nuclear/hydro/pumped storage doesn't change this example much). Under Diversity 1, there would be almost no sharing assumed, and the zone would be an importer for the peak component, so have a negative peak charge. However, **with almost no sharing an OCGT would pay nearly as much for the year round as the wind (or indeed a nuclear plant if there was one). However, the OCGT wouldn't run in practice unless the wind output was low – consequently it is very unfair that it should have to pay high year-round charges**. Indeed, in this example zone A would be a very good location for an OCGT (as the negative peak charge would signify a strong need for generation capacity). **Whilst this may or may not offset the inappropriate year round tariff – the key point is that for a high wind zone the CMP213 year round tariff is not cost reflective and over-allocates cost to the non-wind generation in the zone.** (Poyry 3.2.1.4)

3.24 The proposer suggested that this analysis by Poyry is a helpful description of the specific circumstances where the proposed defect in the CMP213 WACM2 methodology is most apparent and it is this situation where the cost reflectivity of TNUoS charges would be most improved following the implementation of CMP268.

Cost Reflectivity

3.25 The proposer suggested a key test of the modification proposal is whether it is more cost reflective and this question should be considered in the context of three key elements of transmission network investment and charging, namely: 1) The NETS SQSS Economy Criteria. 2) A Cost Benefit Analysis and 3) TNUoS charging methodology. The proposer suggested that these three parts are different from each other because they are used for different purposes, however, they should all be cost reflective of each other as far as practicable. The proposer described relevant features of these three in the context of this modification using the illustrative example of an OCGT:

3.26 NETS SQSS – The proposer noted that modification CMP268 focuses on the TNUoS Year Round background, so the relevant part of the SQSS to compare its cost reflectivity with is the Economy Criteria. The proposer noted that the SQSS Economy Criteria assumes a zero scaling factor for an OCGT. The proposer suggested that this means that in terms of the SQSS, an OCGT does not contribute any cost to network investment within the Economy Criteria irrespective of whether or not flows behind a boundary may be dominated by low carbon generation. The proposer suggested that, therefore to be cost reflective of the SQSS, then the TNUoS Year Round charge (both shared and not shared) for an OCGT should also be zero irrespective of whether or not flows behind a boundary may be dominated by low carbon generation (assuming the OCGT has an ALF of zero).

3.27 Cost Benefit Analysis – The proposer noted that a key tool used in a cost benefit analysis is the National Grid ELSI model. The proposer described that the ELSI model uses as inputs assumptions regarding the cost of fuel of individual stations, from which the model derives generation performance and values of network constraint costs. The proposer suggested that within the ELSI model, an OCGT with a very high cost of fuel would tend exhibit little, or no generation volume, which would imply that in terms of a cost benefit analysis, an OCGT does not contribute any cost to network investment for the purpose of managing constraints within the ELSI model. The proposer suggested that to be cost reflective of a cost benefit analysis, then the TNUoS Year Round charge for an OCGT (both shared and not shared) should also be zero (assuming the OCGT has a zero ALF). This result is also consistent with and cost reflective of the SQSS Economy Criteria as described above.

3.28 TNUoS charging methodology (baseline) – The proposer observed that the baseline CMP213 WACM2 charging methodology can provide a very different result from the SQSS and a Cost Benefit Analysis because an OCGT with a zero load factor may be exposed to a very high TNUoS charge if it is located in a zone with a substantial Not Shared Year Round tariff. The proposer suggested that the conclusion could be drawn that with regard to a zero load factor OCGT in a zone dominated by low carbon generation, the baseline TNUoS charging methodology is not cost reflective of either the SQSS Economy Criteria, or a cost benefit analysis.

3.29 The proposer suggested that the change to the tariff methodology proposed by CMP268 which would apply an OCGT's ALF to all Year Round tariffs (both shared and not shared) would result in a combined Year Round charge for that OCGT of close to zero (assuming an ALF of close to zero) in all circumstances. The proposer suggested this means compared with baseline, CMP268 would result in a TNUoS charge for an OCGT which is more cost reflective of both the SQSS and more cost reflective of a cost benefit analysis.

3.30 The proposer suggested that this result of better cost reflectivity can be generalized to other types of generator. The proposer suggested that the result for an OCGT of the zero scaling factor within the SQSS Economy Criteria and zero (or close to zero) generation within the ELSI model can be generalized to any Conventional Carbon generator which also exhibits a zero, or close to zero load factor. The proposer suggested this result is illustrated in the sample ELSI results from CMP213 which the proposer presented to the workgroup, which shows a Pumped Hydro generator with an apparently zero load factor associated with an apparently zero cost of incremental constraint. The proposer suggested a conclusion could be drawn that the modification CMP268 would be more cost reflective that the baseline for any type of very low load factor Conventional Carbon generator.

3.31 The proposer suggested this result could be further generalized to demonstrate that CMP268 would be more cost reflective for all Conventional Carbon generators in zones with a non-zero Not Shared Year Round tariff irrespective of that generator's ALF. The proposer suggested this could be understood by considering a theoretical 100% load factor CCGT, because in this situation modification CMP268 would result in exactly the same Year Round TNUoS charge as the baseline, therefore in this situation, CMP28 would be as cost reflective as the baseline. The proposer suggested that if, CMP268 is as cost reflective as baseline for a 100% ALF Conventional Carbon generator and more cost reflective than baseline for a 0% load factor, then CMP268 could be expected to also be more cost reflective for Conventional Carbon generators with an ALF anywhere between the two (between 0% and 100%).

4 Workgroup Discussions

4.1 This section is representative of the views of the Workgroup. These discussions have been summarised into five key areas.

1) CMP213 Analysis
    - Effect on tariffs and impact on cost reflectivity of ALF
2) Distributional Impact
3) HVDC Impact
4) Impact on Customer (indirect impact and regional security of supply impact)

It needs to be noted that this discussed followed on from the content presented above by the proposer. This evidence was made available to the Workgroup prior to inform Workgroup discussion. The reason that the proposer’s background and presentation has been presented separately is due to the limited scope of the defect and time constraints rendering it difficult to cover all topics in great detail in the Workgroup discussions.

1) CMP213 Analysis

4.2 Workgroup members felt that the urgent timescales granted to the modification meant that opening up all of analysis carried out by CMP213 was not possible. It was concluded that when Ofgem approved WACM2, Method 1 in the decision letter of CMP213 it advocated this as the most cost reflective option. As a result, the Workgroup decided that the scope of CMP268 needed to only determine whether the proposal better improved the cost reflectivity of the current baseline. The Ofgem decision letter can be accessed using the link below and be found in the ‘Ofgem Decision’ tab:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

4.3 The Workgroup acknowledges that the CUSC Panel have noted that existing analysis collated as evidence to for CMP213 could also be used to support CMP268 however the urgent timescales associated with this modification would not permit the refresh of any of this data.

4.4 Due to the urgent timescale to deliver the modification, the Proposer provided some supporting analysis to the Workgroup which he believes supports his proposal which is detailed in the proposers presentation section. The Proposer suggested that the information indicated that constraint costs across a zone were a function of the amount of carbon and low carbon generation, and that low carbon generation increasingly drove the cost of constraint rather than low load factor carbon generation.

4.5 A workgroup member suggested that given the urgent timescales for consideration of the modification proposal it was not possible to evaluate fully all of the evidence regarding sharing provided under Chapter 4 of the CMP213 Workgroup and in the Appendices to this report (Volume 2). The Workgroup member indicated that the alternative approaches to sharing that were presented in this report were effectively out of scope (e.g. using scaling factor or different diversity options). The Workgroup member suggested that the key issue for consideration was whether there was a case for sharing the non-shared component of the tariff under the current baseline (CMP213 WACM2). Therefore the evaluation should concentrate on method 1 in the CMP213 Workgroup report and the arguments presented by the CMP213 Workgroup with respect to this option.

4.6 The Workgroup considered the case that was made under the Method 1 approach under CMP213. It was highlighted that the key features of this approach included an acceptance that carbon and low carbon could drive transmission investment on a shared basis up to a 50% sharing factor of carbon and low carbon. This was achieved by applying a load factor (ALF) to the shared component of the tariff. Thereafter, the non-shared component of the tariff was applied to the TEC of generation within the zone, recognising that the capacity of generation was the key factor driving investment for the non-shared elements of transmission investment.

4.7 A Workgroup noted in their view that the CMP213 Workgroup report, flagged some members of the CMP213 Workgroup were concerned that "small volumes of carbon in a predominantly low-carbon area would not be adequately recognised under this option" (para 4.70) which highlights the issue raised in modification proposal CMP268. However it was noted that some members of the CMP213 Workgroup believed that method 1 was a "better reflection of how the system was planned and so was more cost reflective overall". In this context a Workgroup member requested that National Grid should consider whether the approach under CMP213 WACM2 better reflected transmission investment planning decisions when compared with CMP268.

4.8 The Workgroup noted that in making their decision the Authority recognised that "the assumption through use of ALF in WACM2 of a perfectly linear relationship between output and constraints is therefore a simplification" (Ofgem decision and CMP213, para 2.15, page 14). However, the Authority also noted that the WACM2 approach "represents a simple, transparent proxy for the impact of a generator on constraint costs, and therefore on transmission investment, taking into account the mix of generation in an area" (Para2.17. In addition, the Authority noted that "it will not precisely reflect the impact that a generator has on transmission investment in every circumstance, especially in the extremes, for example, where there is 0% or 100% of a particular type of generator in a zone" (para 2.17).

4.9 The Workgroup discussed the nature of the sharing of the non-shared component of the tariff. The proposer believes that the current methodology does not properly reflect the costs of individual generators on sharing within a zone and was therefore not cost reflective for that generator with respect to the application of the non-shared component of the tariff. The proposer highlighted that in zones that were dominated by low carbon generation, it was these generators that were driving the costs of constraints.

4.10 One Workgroup member argued that with respect to the non-shared component it was all generation (carbon and low carbon) in a zone that was considered to be responsible for the transmission investment driver under the CMP213 WACM2 approach and not exclusively the low carbon generation. This reflects the fact that the tariff model is zonal rather than nodal in nature. Consequently it is cost reflective for all generators within the zone to face the non-shared component of the tariff.

4.11 It was noted by one Workgroup member that under the current baseline (CMP213 WACM2) low load factor carbon generation has a significant discount with respect to the overall Year-Round tariff. These generators currently pay the shared component based on the ALF (which would be a low cost for low load factor plant) and only pay the shared component with respect to TEC. This discount provided cost reflective marginal signals for generators in that zone based on the CMP213 WACM2 approach.

4.12 In discussing the investment drivers a Workgroup member noted that the cost of constraints and the type of plant was historically a use for concern with a risk that certain plant could have locational market power. However, it was noted by the Workgroup that the Transmission Constraint Licence Condition now in force should substantially remove the potential for market power in such circumstances.

4.13 This Workgroup member said that in their understanding of System Operations, this supposition seemed unlikely to be accurate in practice; when there is high wind output in such areas (and thus to a degree nationally), the lack of “inertia” from wind may mean that National Grid takes steps to ensure that more of the carbon type plant is running nationally, including in these areas.

4.14 They also noted that another reason why National Grid may require output from the carbon plant in these areas, even at times of high low carbon generation there, for reasons of voltage or stability support, due to their good characteristics from a System Operator point of view, unrelated to local energy balance or thermal circuit limits.

4.15 The Workgroup member furnished the Workgroup with a graph of data (Figure 4) from every half hour in 2015 that they believe bears out this supposition, as well as circulating the underlying data/spreadsheet. They noted that by bundling the generation data points into deciles by wind output, what appears to be the very relationship that was conjectured is seen. They used data for the metered data from a representative sample of 6 Scottish generators (as visible in central systems), namely Areleoch, Blacklaw, Harestanes, Clyde, Griffin, and Hadyard Hill, choosing this area as they considered it to be the most marked case of an export-constrained area with more than half renewable capacity. They also noted that in the windiest 10% of hours (Decile 10, the right-most bar below), the output from the Scottish pumped storage stations (green) and Peterhead (blue) are both significantly higher than in the least windy 10% of hours, indeed higher than in any other decile in-between”. The analysis was not extended due to lack of time to other areas with relevant conventional carbon assets and a non-zero non-shared generation TNUoS charge elements such as the Northern English TNUOS charging zones down to zone 15, or zone 22.

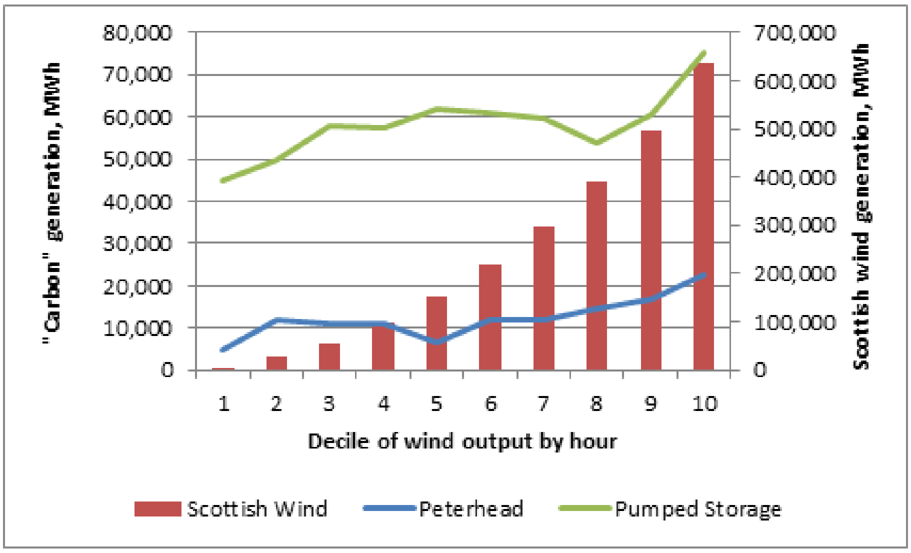


Figure 4: 2015 Analysis

4.16 The proposer highlighted what he believed to be two key flaws in this analysis.

4.16.1 Firstly in principle, a theoretical requirement for the System Operator to constrain on a conventional carbon generator behind a constrained boundary (e.g. for inertia, voltage support, stability) does not represent a marginal cost of transmission network investment. This is because a marginal increase in conventional carbon generation in the affected area does not cause an increase in required transmission network for this purpose and likewise a reduction in conventional carbon in the affected area does not cause a reduction in required transmission network for this purpose. Therefore since this is not an avoidable cost which is either caused by, or avoided by an incremental conventional carbon generator, then it would not be cost reflective to attempt to incorporate this into the locational TNUoS tariff for conventional carbon generators.

4.16.2 Secondly, in practice, the proposer believed that the data used in the analysis has not been interpreted correctly with regard to the following:

- **Constraints are driven by low net demand, not just high gross wind –** The analysis above suggests a correlation between higher wind generation and higher pumped storage generation, but fails to illustrate any correlation with periods of constraint, which would be the more relevant question. By contrast, all this approach is doing is illustrating the effect of winter weather i.e. winter tends to be windier and it also tends to be colder, which tends to cause relatively high wind output and higher dispatch of peaking generators in order to earn relatively high prices in the wholesale power market. However, during such periods when demand is relatively high, sharing continues to take place and conventional carbon generators can generate at the same time as low carbon generators without causing network constraints.

- **Peterhead data set was so limited, that it can not be relied upon for any conclusions** – The only substantial data shown for Peterhead was for the single month of December and even then this did not represent normal market operating characteristics. Therefore it is meaningless to attempt to draw a correlation between Peterhead's single month of operating in December compared with a full 12 months of wind data. The data showed zero generation during the majority of the period analysed namely 8 months March 2015 to October 2015. The data also showed an average load factor for Peterhead of zero between January 2015 and October 2015, rising to 1% in November, then only 13% in December.

4.17 An alternative interpretation of the same data was provided by the proposer as described below (Figure 5). This calculated a net demand profile for Scotland by scaling up the sample wind data to represent the total Scottish wind fleet and also a scaled down set of National Grid published demand data (I014_ND) to represent demand in Scotland. This Scottish net demand was then compared with pumped storage net generation, as well as Scottish nuclear stations as shown in the graph below.

4.18 The proposer noted that they were keen not to re-open the CMP213 debate and keep the scope of the mod narrow.

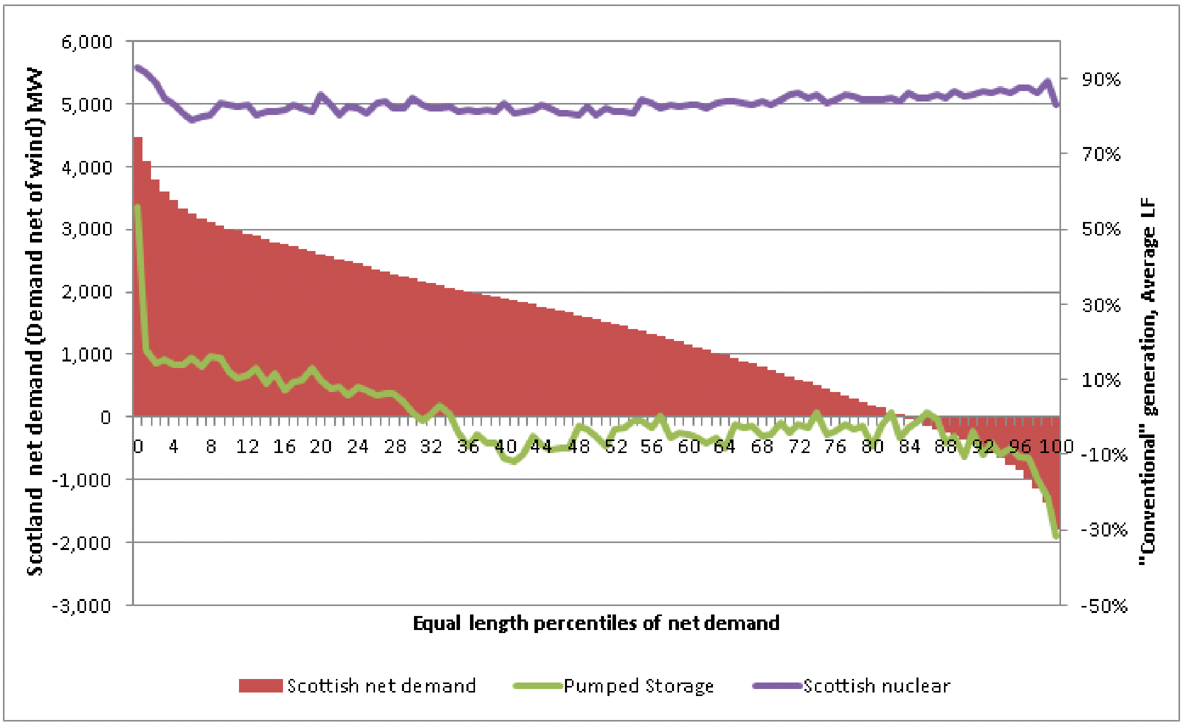


Figure 5: Net Demand Profile for Scotland

4.19 The proposer suggested that the graph in Figure 5 clearly shows several key conclusions including:

4.19.1 Firstly, pumped storage is tending to relieve constraints, not cause them - The dispatch behaviour of Scottish Pumped Storage is tending to help the transmission network by tending to relieve constraints, so tending to cause a reduction in network cost. This is illustrated by the right hand side of the green curve which shows a net generation load factor becoming increasingly negative (pumping– this, like its generation, entails synchronous operation of pumped storage assets) and reaching circa minus 30% during periods when net demand is lowest (associated with relatively high wind combined with relatively low demand). These are the periods when constraints are most likely to occur and it is clear from the data that during those periods, the pumped storage was tending to pump more and generate less, therefore tending to help the transmission system. This result is consistent with the modification proposal to provide a more full sharing benefit to conventional carbon generation even if they are located in parts of the network which are dominated by low carbon generation.

4.19.2 Secondly, conventional carbon is sharing with the wind - the left hand side of the graph shows a high degree of sharing during periods when net demand is high (associated relatively low wind and relatively high demand). These are the periods when there is the lowest likelihood of constraints occurring and these are also the periods when the generation from pumped storage has been highest. This result is consistent with the modification proposal to provide a more full sharing benefit to conventional carbon generation even if they are located in parts of the network which are dominated by low carbon generation.

4.20 Thirdly, it appears appropriate to treat two types of conventional generation differently i.e. conventional carbon compared with conventional low carbon - The graph shows a stark difference in the operating characteristics of the Scottish nuclear stations compared with the pumped storage. The nuclear stations only adjust their average load factor within a relatively narrow band and therefore maintain a relatively high load factor irrespective of the level of net demand in Scotland. This demonstrates that in contrast to the pumped storage, the nuclear stations are not sharing with the wind during periods of low net demand when constraints are most likely to occur. Therefore this data supports the position of the proposer that it is appropriate when applying TNUoS tariffs for the tariff formula to make a distinction between the two classes of conventional generation as per the proposal to provide a sharing benefit across all Year-Round circuits for those classed as “Carbon”, but not provide this sharing benefit to those classed as “Low Carbon”.

4.21 A Workgroup member noted the adverse effect of the modification in indicative 2017/18 tariffs on Seabank power station, a CCGT of 800 MW, which based on indicative modelling circulated to the Workgroup by National Grid, could be worse off by a rough indicative estimate of £5.8m p.a. (at least in 2017/18; there is no forecast of the track of CMP268 effects in later years) in terms of extra TNUoS costs it would face if CMP268 were passed. Even allowing for a large error margin on the non-guaranteed indicative effects grid had circulated, it looked as though it can reasonably confidently be said that this asset could face a substantial asset-specific adverse financial effect, whatever the exact number. It is possible, it was suggested, that the asset might close in the fact of extra annual costs of this magnitude, with possible effects on security of supply; the lack of good signs of new-build CCGT is, it was remarked, a live topic in many conversations around energy policy and security of supply in Britain at present.

4.22 An alternative view was provided to point out that even after the adverse financial impact of the proposal for Conventional Carbon in generation charging zone 22 (the zone for Seabank), that zone would still provide one of the lowest generator TNUoS charges of any zone on the GB system. The financial impact of the modification proposal would be to change the locational element of the TNUoS tariff paid by Seabank from being a negative locational charge (receipt of revenue) to a positive locational charge. It is important to note that the monetary impact on Seabank appears relatively large because its small change in tariff is applied to a much larger TEC at 3 to 4 times the TEC of Peterhead and Foyers. After the Generator Residual is applied (forecast by National Grid to be negative in later years), the total TNUoS charge for a low load factor conventional carbon station in zone 22 may be expected to be remain negative from 2018/19 and continue to become increasingly negative over time.

4.23 It was suggested by a Workgroup member thatif parties are concerned that expensive TNUoS charges may potentially provide a price signal for generating stations to close and any impact on security of supply this may have, then it may be more appropriate to consider zones where generators currently face the highest TNUoS charges compared with the rest of the GB system.

4.24 This workgroup member believed that the proposer’s recollection of the origin of the diversity option under CMP213 was not accurate. The diversity option came about because of work which was undertaken to try to prove the relationship between the ALF of power stations in a zone and the constraint costs which arise. This involved modelling scenarios on a simplified model of the network, “ELSI”. This modelling showed that sometimes such a relationship existed, but that that this relationship broke down in certain circumstances. This certainly appeared to be the case when there was less diversity in a zone.

4.25 The working group member agreed that the main driver of this was being unable to access bids closer to market price, although this was not the only cause. Issues such as the coincidence of running at times of constraints also had a bearing. The working group member noted that CMP213 workgroup did not conclude that in such circumstances the higher carbon plant should be treated differently due to driving a lower level of investment, as the proposer asserts as the rationale for CMP268. The only conclusion the CMP213 working group was able to make given the analysis available was that the relationship broke down when there was less diversity, due to a lack of ability to access lower cost bids and that the methodology should reflect this. This is borne out in the CMP213 working group report which says:

"*4.110 The Workgroup found that, where there was insufficient diversity of generation plant types behind a transmission network constraint, the SO would no longer be able to accept bids from a generator close to price of the system marginal plant. In this case the incremental cost of constraints would increase.*"

4.26 The working group member also referred to paragraph 1.15 of Ofgem's decision letter on CMP213. "*1.15. The Year Round tariff would be further adjusted into a 'shared' and 'non-shared' element. The split is based on the proportion of low carbon generation in an area. If the level of low carbon plant behind a boundary is 50% or less, then the entire Year Round tariff is shared. Once this percentage exceeds 50%, an increasing proportion is considered 'non-shared'. This change is to reflect that plant in zones dominated by low carbon plant tend to drive higher levels of constraint costs and therefore investment than if there is a range of plant in a zone.*" The workgroup member noted that this comment from Ofgem refers to the fact that plant in a zone tends to drive higher levels of constraint costs, but does conclude that it is just lower carbon plant which is doing so.

4.27 The workgroup member pointed out that the CMP213 solution was also a simplified approach to reflect the effect on the zone as a whole, but clearly a more sophisticated, targeted and complex approach was potentially possible. This was reflected in the CMP213 workgroup report which said: "*4.137 whilst annual load factor is generation plant specific, the diversity element is related to the zonal availability of sufficient non low carbon plant (or simply – Carbon plant) in a TNUoS zone (i.e. plant with a near marginal bid price). As the Workgroup were minded not to look for a complex solution based on bid price, Method 1 would utilise the ratio of cumulative low carbon (LC) to carbon (C) generation TEC behind a zonal transmission boundary as set out in paragraph 4.130 to establish what proportion of the associated incremental kilometres making up the transmission boundary length were shared or not shared.*"

4.28 The workgroup member pointed out that this point was recognised by Ofgem too in its decision letter "*2.17. We therefore consider that WACM 2 is an improvement on the existing charging methodology. It represents a simple, transparent proxy for the impact of a generator on constraint costs, and therefore on transmission investment, taking into accounts the mix of generation in an area. However, it will not precisely reflect the impact a generator has on transmission investment in every circumstance, especially at the extremes, for example, when there is 0% or 100% of a particular type of generator in a zone. A more accurate calculation that captured all the factors that affect investment decision-making would require considerably more complexity. We think this would make the charging methodology less transparent and more difficult to forecast. We consider that this would be a barrier to entry, reduce competition and would offset any gains from the additional precision. It will never be possible to exactly capture the impact of an individual generator on the system while remaining within the principles of the ICRP methodology. Balancing accuracy with the simplicity and* *transparency of tariffs is an important part of the ICRP methodology because of the impact these factors have on competition.*" Therefore, the workgroup member believed that if the proposer wished to have the specific impact that particular type of higher carbon plant had on the system reflected in the charging methodology, this would require a more sophisticated change than was being proposed under CMP268. That is, new analysis would need to be undertaken and changes would need to be made to the transport model and the tariff model. It would not be sufficient to make a simple change to the tariff model as proposed under CMP268, as this would simply provide a competitive advantage to one or two generators without necessarily improving cost reflectivity of the system.

4.29 Given that the diversity option was focussed on the ability to access lower cost bids, the workgroup member considered that the current methodology gave the correct signals. The likelihood of being able to access lower cost bids is increased if there is more lower cost generation in the zone. The current price signals reflect this by increasing the amount of shared circuits as the amount of diversity increases. This workgroup member believed that the proposer was incorrect to assert that the current methodology gives a signal for lower cost bid plant to close. Instead it gives a signal for more such plant to locate in the area, as the result of this is to increase the amount of sharing in the price signal. The workgroup member pointed out that a generator would not make an investment decision based on the current price signal, as the proposer asserts, but on what it believed the signal would be after decision.

4.30 In discussing the investment drivers a Workgroup member noted that the cost of constraints was also driven by the amount of competition behind the constraint to provide low cost bids. The workgroup member believe that a small amount of higher carbon plant mixed with low carbon plant may not provide a wide enough pool of lower cost plant to provide effective competition. However, it was noted by the Workgroup that the Transmission Constraint Licence Condition is now in force.

2) <u>Distributional Impact</u>

4.31 Some workgroup members believe that, as it cannot be proven that CMP268 improves the cost reflectivity of the transmission charging methodology, it is simply aimed at providing an unfair competitive advantage to a small subset of participants through redistributing costs between different companies. The analysis that National Grid has undertaken in this respect shows that this advantage would be considerable. The result of this would be that competition in the generation market is distorted. The most significant impact of this would be if this affected the forthcoming Capacity Market auctions in December. Given that the modification was given urgent status on the basis that it should be resolved in time for these auctions, this seems to be a likely outcome.

4.32 Another workgroup member suggested those generators benefiting from CMP268 may experience a reduction in their TNUoS tariff, but even after this reduction, they are likely to still be paying amongst the highest £/kW TNUoS tariffs of any generator in GB, so it would be misleading to suggest this gave them any form of cost advantage over other generators. The same workgroup member also suggested that if the reduced £/kW TNUoS tariff following CMP268 is more cost reflective than the baseline, then it implies it represents a correction to a pre-existing market distortion because it means by comparison, it is the baseline which currently causes a discriminatory, non-cost reflective, redistributional economic disadvantage for those affected stations."Table 1 shows the impact on revenue recovery for 2017/18 if the modification was implemented. As a limited number of Generators will have their

Annual Load Factor applied to their Year Round Not Shared (YRNS) Tariff, this results in less revenue (£11.71m) recovered through that particular locational element. To counter act this and maintain overall revenue recovery this then results in the Residual increasing by 0.17 £/kW.

4.33 Table 2 lists those Generators contracted for 2017/18 who will be classed as Conventional Carbon and reside in a Generation zone which has a YRNS tariff (i.e. not 0). These Generators will have their Annual Load Factor applied to their YRNS Tariff. For Generators who currently are forecasted for 2017/18 to have a positive YRNS this results in their forecasted liability reducing. The opposite happens in zones where the YRNS is negative.

4.34 As reducing the negative YRNS tariff increases a Generators liability there could be occasions where the impact on all Generators is a reduction in the Residual.

3) HVDC Impact

4.35 For purely illustrative purposes, further analysis of the impact on 2017/18 tariffs was undertaken to show the effect on Conventional Carbon if the HVDC link was not built. As the HVDC link is classed as a Year Round Shared circuit, this increases tariffs for those zones which utilise the link. Therefore without the HVDC link the overall benefit to Convention Carbon Generators decreases.

4.36 Please note that this analysis was undertaken to show how underlying changes in flows or circuits affecting the locational element of tariffs will affect the impact of this modification on certain Generators, and **not** as a potential scenario for 2017/18 tariffs

Future Years

4.37 Tables 4 to 6 show tariffs from the 5 year forecast undertaken in 2016, which forecasted tariffs out to the 2020/21 year. This shows that YRNS tariffs for Scottish Zones do increase slightly. Therefore if all things stay equal in terms of contracted Generation then this will increase the residual over and above what the residual is currently forecasted

Impact on Revenues 2017/18

	Original	CMP268	Change
Total Infrastructure Revenue (£m)	2735.14	2735.14	
Proportion from Generation (£m)	390.26	390.26	
Proportion from Demand (£m)	2344.88	2344.88	
Local Substation Charge Revenue (Onshore + Offshore) (£m)	241.28	241.28	
Residual Charge for Generation(£/kW)	-2.28	-2.10	
Residual Charge for Demand (£/kW)	47.96	47.96	
Residual Charge Generation broken down			
Proportion from Generation	390.26	390.26	
less revenue from Local tariffs			
Peak	130.15	130.15	
Year Round Shared	20.50	20.50	
Year Round Not Shared	138.03	126.32	-11.71
All Offshore + Onshore Local Substation	241.28	241.28	
Onshore Local Circuit	15.80	15.80	
	545.75	**534.04**	
Revenue to collect through Residual	-155.49	-143.78	11.71
Gen Base	68.31	68.31	
Residual Charge for Generation(£/kW)	-2.28	-2.10	0.17

Table 1: Impacts on Revenue 2017/18

Generation Input Data				NEW	NEW	NEW	NEW		NEW	EXISTING	
Station	Generator Type	Max Contracted TEC at Peak (Transport Model TEC)	ALF	Conventional Carbon	Non Conventional Carbon	Conventional Carbon	Conventional Carbon * ALF	Gen Zone	Year Round Not Shared	Year Round Not Shared	Impact of CMP268 YRNS
BP Grangemouth	CHP	120	61.60%	Yes	0	120	74	9	8.158948485	13.24567811	- 610,407.55
Cruachan	Pump Storage	440	9.23%	Yes	0	440	41	8	1.426292143	15.45023194	- 6,170,533.51
Drax (Biomass)	Biomass	1905	81.80%	Yes	0	1905	1558	15	0.146887797	0.179560209	- 62,240.95
Drax (Coal)	Coal	2001	81.80%	Yes	0	2001	1637	15	0.146887797	0.179560209	- 65,377.50
Fiddlers Ferry	Coal	1455	49.28%	Yes	0	1455	717	15	0.08849286	0.179560209	- 132,502.99
Foyers	Pump Storage	300	15.39%	Yes	0	300	46	1	2.643040442	17.1725935	- 4,358,865.92
Immingham	CHP	1218	54.19%	Yes	0	1218	660	15	0.097301827	0.179560209	- 100,190.71
Lynemouth Power Station	Coal	376	58.02%	Yes	0	376	218	13	2.52827727	4.357254511	- 687,695.44
Peterhead	CCGT	400.00	41.88%	Yes	0	400	168	2	7.19158344	17.1725935	- 3,992,404.03
Saltend	CCGT	1100	79.87%	Yes	0	1100	879	15	0.143422616	0.179560209	- 39,751.35
Seabank	CCGT	1234	26.18%	Yes	0	1234	323	22	-1.60712423	-6.138695111	5,591,958.47
Sellafield	CHP	155	17.34%	Yes	0	155	27	14	0.489572864	2.823518556	- 361,761.58
South Humber Bank	CCGT	1365	32.11%	Yes	0	1365	438	15	0.057650536	0.179560209	- 166,406.70
Wilton	CCGT	141	9.66%	Yes	0	141	14	13	0.420702601	4.357254511	- 555,053.82
											-£11,711,233.58

Table 1: 2017/18 Impacts on Parties Costs

Generation Input Data				NEW	NEW	NEW	NEW		NEW NO HVDC	EXISTING NO HVDC	
Station	Generator Type	Max Contracted TEC at Peak (Transport Model TEC)	ALF	Conventional Carbon	Non Conventional Carbon	Conventional Carbon	Conventional Carbon * ALF	Gen Zone	Year Round Not Shared	Year Round Not Shared	Impact of CMP268 YRNS
BP Grangemouth	CHP	120	61.60%	Yes	0	120	74	9	4.342178	7.049327	- 324,857.84
Cruachan	Pump Storage	440	9.23%	Yes	0	440	41	8	0.746682	8.088389	- 3,230,351.29
Drax (Biomass)	Biomass	1905	81.80%	Yes	0	1905	1558	15	0.001437	0.001756	- 608.81
Drax (Coal)	Coal	2001	81.80%	Yes	0	2001	1637	15	0.001437	0.001756	- 639.49
Fiddlers Ferry	Coal	1455	49.28%	Yes	0	1455	717	15	0.000866	0.001756	- 1,296.07
Foyers	Pump Storage	300	15.39%	Yes	0	300	46	1	1.523510	9.898681	- 2,512,551.36
Immingham	CHP	1218	54.19%	Yes	0	1218	660	15	0.000952	0.001756	- 980.01
Lynemouth Power Station	Coal	376	58.02%	Yes	0	376	218	13	1.487257	2.563151	- 404,536.21
Peterhead	CCGT	400.00	41.88%	Yes	0	400	168	2	4.145395	9.898681	- 2,301,314.23
Saltend	CCGT	1100	79.87%	Yes	0	1100	879	15	0.001403	0.001756	- 388.83
Seabank	CCGT	1234	26.18%	Yes	0	1234	323	22	-1.514004	-5.783007	5,267,948.90
Sellafield	CHP	155	17.34%	Yes	0	155	27	14	0.440849	2.542514	- 325,758.04
South Humber Bank	CCGT	1365	32.11%	Yes	0	1365	438	15	0.000564	0.001756	- 1,627.70
Wilton	CCGT	141	9.66%	Yes	0	141	14	13	0.247478	2.563151	- 326,509.89
											- 4,163,470.86

Table 2: 2017/18 Impact without HVDC

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional 80% Load Factor	Intermittent 40% Load Factor
Zone	**Zone Name**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**
1	North Scotland	0.33	13.48	19.30	-3.38	27.03	21.31
2	East Aberdeenshire	0.66	4.78	19.30	-3.38	20.40	17.83
3	Western Highlands	-0.40	11.85	18.61	-3.38	24.31	19.97
4	Skye and Lochalsh	-4.53	11.85	19.84	-3.38	21.41	21.20
5	Eastern Grampian and Tayside	-0.19	10.22	17.32	-3.38	21.92	18.03
6	Central Grampian	1.63	10.91	18.11	-3.38	25.09	19.10
7	Argyll	0.47	9.00	26.77	-3.38	31.06	26.99
8	The Trossachs	0.82	9.00	15.85	-3.38	20.49	16.07
9	Stirlingshire and Fife	-0.25	5.01	13.29	-3.38	13.66	11.91
10	South West Scotland	1.39	8.15	15.00	-3.38	19.53	14.88
11	Lothian and Borders	2.33	8.15	8.84	-3.38	14.31	8.72
12	Solway and Cheviot	0.95	4.79	8.07	-3.38	9.46	6.60
13	North East England	2.79	3.01	4.24	-3.38	6.05	2.06
14	North Lancashire and The Lakes	1.50	3.01	3.11	-3.38	3.64	0.94
15	South Lancashire, Yorkshire and Humber	3.62	1.18	0.21	-3.38	1.40	-2.70
16	North Midlands and North Wales	3.06	-0.29		-3.38	-0.55	-3.50
17	South Lincolnshire and North Norfolk	0.71	0.63		-3.38	-2.17	-3.13
18	Mid Wales and The Midlands	1.02	-0.11		-3.38	-2.44	-3.42
19	Anglesey and Snowdon	4.05	-0.13	0.00	-3.38	0.57	-3.43
20	Pembrokeshire	9.01	-4.99		-3.38	1.64	-5.38

21	South Wales & Gloucester	6.15	-4.98		-3.38	-1.21	-5.37
22	Cotswold	3.09	1.43	-6.42	-3.38	-5.57	-9.23
23	Central London	-5.26	1.43	-6.80	-3.38	-14.30	-9.61
24	Essex and Kent	-3.57	1.43		-3.38	-5.81	-2.81
25	Oxfordshire, Surrey and Sussex	-1.10	-3.44		-3.38	-7.23	-4.76
26	Somerset and Wessex	-1.22	-4.86		-3.38	-8.49	-5.33
27	West Devon and Cornwall	0.22	-6.28		-3.38	-8.19	-5.89

Table 4: 2016 5 Year Forecast 2018

Generation Tariffs		**System Peak Tariff**	**Shared Year Round Tariff**	**Not Shared Year Round Tariff**	**Residual Tariff**	**Conventional 80% Load Factor**	**Intermittent 40% Load Factor**
Zone	**Zone Name**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**
1	North Scotland	2.38	11.09	22.30	-5.37	28.17	21.36
2	East Aberdeenshire	2.78	3.93	22.30	-5.37	22.85	18.50
3	Western Highlands	2.06	10.23	21.53	-5.37	26.41	20.25
4	Skye and Lochalsh	-2.19	10.23	22.77	-5.37	23.40	21.50
5	Eastern Grampian and Tayside	4.03	9.99	21.23	-5.37	27.88	19.85
6	Central Grampian	3.58	9.03	19.61	-5.37	25.04	17.86
7	Argyll	2.60	7.66	28.01	-5.37	31.36	25.70
8	The Trossachs	2.82	7.66	17.26	-5.37	20.84	14.96
9	Stirlingshire and Fife	1.85	7.10	16.72	-5.37	18.89	14.19
10	South West Scotland	2.42	6.69	16.20	-5.37	18.60	13.51
11	Lothian and Borders	3.46	6.69	10.46	-5.37	13.90	7.77
12	Solway and Cheviot	1.71	3.99	9.13	-5.37	8.66	5.35
13	North East England	3.37	2.38	4.72	-5.37	4.63	0.30
14	North Lancashire and The Lakes	1.76	2.38	3.37	-5.37	1.66	-1.05

15	South Lancashire, Yorkshire and Humber	4.14	0.63	0.26	-5.37	-0.48	-4.86
16	North Midlands and North Wales	3.21	-0.45		-5.37	-2.51	-5.55
17	South Lincolnshire and North Norfolk	1.74	-0.10		-5.37	-3.71	-5.41
18	Mid Wales and The Midlands	0.93	0.19		-5.37	-4.29	-5.29
19	Anglesey and Snowdon	3.95	0.02	0.00	-5.37	-1.41	-5.36
20	Pembrokeshire	8.58	-5.39		-5.37	-1.10	-7.53
21	South Wales & Gloucester	5.53	-5.46		-5.37	-4.20	-7.55
22	Cotswold	2.34	1.97	-7.52	-5.37	-8.97	-12.10
23	Central London	-5.47	1.97	-7.18	-5.37	-16.45	-11.77
24	Essex and Kent	-3.73	1.97		-5.37	-7.53	-4.58
25	Oxfordshire, Surrey and Sussex	-1.12	-3.09		-5.37	-8.96	-6.61
26	Somerset and Wessex	-2.01	-5.53		-5.37	-11.80	-7.58
27	West Devon and Cornwall	-2.08	-8.41		-5.37	-14.18	-8.73

Table 5: 5 Year Forecast 2019/20.

Generation Tariffs		**System Peak Tariff**	**Shared Year Round Tariff**	**Not Shared Year Round Tariff**	**Residual Tariff**	**Conventional 80% Load Factor**	**Intermittent 40% Load Factor**
Zone	**Zone Name**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**
1	North Scotland	2.58	11.82	22.83	-9.69	25.18	17.87
2	East Aberdeenshire	3.04	4.46	22.83	-9.69	19.75	14.92
3	Western Highlands	2.22	12.43	23.38	-9.69	25.86	18.66

4	Skye and Lochalsh	2.22	12.43	26.22	-9.69	28.70	21.50
5	Eastern Grampian and Tayside	4.21	11.06	21.48	-9.69	24.85	16.21
6	Central Grampian	3.54	10.03	19.65	-9.69	21.52	13.96
7	Argyll	2.61	8.58	27.69	-9.69	27.47	21.43
8	The Trossachs	2.70	8.58	17.01	-9.69	16.89	10.75
9	Stirlingshire and Fife	2.12	8.25	16.67	-9.69	15.70	10.28
10	South West Scotland	2.54	7.66	15.89	-9.69	14.87	9.27
11	Lothian and Borders	3.65	7.66	10.25	-9.69	10.34	3.62
12	Solway and Cheviot	1.75	5.01	8.52	-9.69	4.58	0.83
13	North East England	3.74	3.96	5.53	-9.69	2.75	-2.58
14	North Lancashire and The Lakes	1.77	3.96	2.00	-9.69	-2.75	-6.11
15	South Lancashire, Yorkshire and Humber	4.15	0.52	0.22	-9.69	-4.90	-9.27
16	North Midlands and North Wales	3.18	-0.44		-9.69	-6.87	-9.87
17	South Lincolnshire and North Norfolk	1.66	-0.15		-9.69	-8.16	-9.75
18	Mid Wales and The Midlands	0.83	0.47		-9.69	-8.49	-9.51
19	Anglesey and Snowdon	2.71	1.32		-9.69	-5.93	-9.17
20	Pembrokeshire	8.65	-5.50		-9.69	-5.45	-11.89
21	South Wales & Gloucester	5.69	-5.69		-9.69	-8.55	-11.97
22	Cotswold	2.28	2.09	-7.83	-9.69	-13.57	-16.69
23	Central London	-5.65	2.09	-7.62	-9.69	-21.30	-16.48
24	Essex and Kent	-3.75	2.09		-9.69	-11.77	-8.86
25	Oxfordshire, Surrey and Sussex	-1.26	-3.06		-9.69	-13.40	-10.92
26	Somerset and Wessex	-1.86	-3.62		-9.69	-14.45	-11.14
27	West Devon and Cornwall	-2.04	-7.89		-9.69	-18.04	-12.85

Table 6: 2016 5 Year Forecast 2020/21.

4) Impact on Customer (indirect impact and regional security of supply impact)

4.38 This section details the impact on the customer as identified by the Workgroup.

4.39 The Workgroup discussed the impact this proposal will have on customers, both direct and indirect and also the impact this will have on regional security of supply.

4.40 The Workgroup agreed that this impacts on generation residual where there is a decrease in the negative residual this will increase costs for all generators. The modification could result in certain circumstances increase the costs for generators due to adjustments in the residual. These effects may have a marginal impact on regional security of supply. This is a re-apportion of costs for generators.

4.41 The Workgroup concluded that this modification would have no impact on the demand residual.

4.42 In one Workgroup members view it was noted that if this defect is not corrected, then it would result in at least three key types of harm to regional peak security:

4.43 Firstly, competition is distorted by a non-cost reflective economic disadvantage for Conventional Carbon generators which are located in zones with a high proportion of low Carbon generation.

4.44 Secondly, the defect will cause higher cost to customers than would otherwise be the case. This is because generators will face the incentive to make investment, or closure decisions which do not reflect the economic impact on the investment cost of the transmission network which they cause. This would result in an outcome which is less economically efficient at a higher cost to society and ultimately a higher cost to customers.

4.45 Thirdly, there is a locational security of supply risk. The current defect provides the perverse economic price signal that as more intermittent low carbon plant is built in a zone, then low load factor peaking plant experience higher TNUoS charges. This is a self-reinforcing "death spiral" for low load factor peaking plant because as the charges increase and low load factor peaking plant are encouraged to close, then this would further reduce the assumed degree of sharing, which would feed back to further increase the price signal for remaining low load factor peaking plant to close. If left uncorrected, then for that zone, the "death spiral" would result in a shortage of low load factor peaking plant and an increasing reliance on imported power to meet peak demand, which would result in an increasing risk to security of supply for customers in that zone.

4.46 Another workgroup member noted that the above comments were predicated on the modification providing a more cost reflective signal. This workgroup member believed that the price signals were indeed appropriate as they encouraged more diversity into an area which would increase the amount of sharing. This workgroup member noted that the modification would certainly provide some plant with a considerable cost advantage over others. It was not clear whether the modification would prevent plant from closing inappropriately however without further analysis. The workgroup members noted that it could similarly be argued that if the CMP268 signals were not cost reflective, then this could indeed result in inappropriate plant closures. Another workgroup member suggested those generators benefiting from CMP268 may experience a reduction in their TNUoS tariff, but even after this reduction, they are likely to still be paying amongst the highest £/kW TNUoS tariffs of any generator in GB, so it would be misleading to suggest this gave them any form of cost advantage over other generators. A workgroup member also suggested that if the reduced £/kW TNUoS tariff following CMP268 is more cost reflective than the baseline, then it implies it represents a correction to a pre-existing market distortion in the form of a non-cost reflective, redistributionary economic disadvantage for those affected stations under the baseline.

5 Impact and Assessment

Impact on the CUSC

5.31 Changes to CUSC Section 14 – Part 2 – The Statement of the Use of System Charging Methodology,

5.32 Changes to CUSC Section 14 Section 1 – The Statement of the Transmission Use of System Charging Methodology

Impact on Greenhouse Gas Emissions

5.33 None identified.

Impact on Core Industry Documents

5.34 None identified.

Impact on other Industry Documents

5.35 None identified.

6 Proposed Implementation and Transition

6.1 The Workgroup discussed how the proposed arrangements would transition and be implemented. The details of their proposed implementation and transition are shown in this section.

Implementation timeline

6.2 New tariffs are to be applied from 1 April 2017. It is proposed that the new tariff formula arising from CMP268 should apply from charging year starting 1 April 2017.

6.3 The Authority have granted an urgent status for this Proposal on the basis that an Authority decision should be reached by the end of November to provide certainty for market participants placing bids in the T-4 Capacity auction for 2020/21 which is expected to take place in the first week of December 2016.

6.4 National Grid Draft TNUoS tariffs (December 2016) – If a decision is not published by the time Draft Tariffs are due to be published National Grid will publish two scenarios for Generation Tariffs; Status Quo and CMP268.

6.5 If decision is not published by end of January 2016 then this will require a mid-year tariff change.

6.6 The Workgroup discussed how the proposed arrangements would transition and be implemented. The details of their proposed implementation and transition are shown in this section.

System Changes

6.7 There will be no System Changes for Industry. All required changes made will revolve around changes to National Grid's internal billing System. As discussed within the report, the System will now require an extra attribute to recognise the concept of Carbon and Low carbon, and the combination of this with Peak (Conventional), will alter how the Year Round not Shared Tariff is calculated for those particular Generators.

Costs to Implement

6.8 National Grid have requested a quote from the providers of our current billing system to undertake the change but due to the timescales of this modification this has not yet been received so cannot be provided within this consultation. Further consultation reports will have an updated figure. For reference Project Transmit was quoted at ~£1million. This System change will not be in that magnitude. As changes for Project Transmit have only recently been tested and implemented a change so soon afterwards is inefficient.

Communications

6.9 This modification directly affects a limited number of Generators from a locational TNUoS perspective. National Grid will contact them directly to make them aware of this modification. All Generators will see a change in the Residual element of their tariff (please see analysis) but only in the magnitude of changes historically seen between quarterly forecasts of tariffs. Therefore communication for these Generators will be via the Quarterly forecasts and the National Grid Customer Account Managers.

7 Workgroup Consultation Questions

7.1 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:

Workgroup Consultation questions;

Q1: Do you believe that the CMP268 Original proposal better facilitates 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.

7.2 Please send your response using the response proforma which can be found on the National Grid website via the following link: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP268/

7.3 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/

7.4 Views are invited upon the proposals outlined in this report, which should be received by **5pm** on **30 September 2016**. Your formal responses may be emailed to: cusc.team@nationalgrid.com

7.5 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 market "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.

7.6 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".

Annex 1 – CMP268 CUSC Modification Proposal Form

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP268

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal

Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits

Submission Date

26th July 2016

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

Description of the defect

The current charging methodology fails to reflect the fact that different types of "Conventional" generation, e.g. CCGTs compared to Nuclear, cause different transmission network investment costs to be incurred due to their different network sharing characteristics.

The defect identified by this modification proposal relates to a type of generating plant which the existing charging methodology defines as being both "Conventional" and "Carbon". For the purpose of simplicity, this modification proposal refers to this group of generators as "Conventional Carbon". To aid understanding of the modification proposal, an explanation is provided in the section below and this ""Conventional Carbon" generator type is highlighted in red in the accompanying table.

The defect is that there is a specific circumstance where the charging methodology is not cost reflective because it fails to recognise that Conventional Carbon plant does in fact continue to fully share all Year Round circuit costs even in circumstances when the proportion of plant which is Low Carbon exceeds 50%. The defect in the current methodology delivers the result that "Conventional Carbon" plant in zones with a significant Not-Shared Year-Round tariff are charged TNUoS tariffs which are higher than the cost they cause and therefore the charging methodology is not cost-reflective for those plant.

Within the current methodology, when the penetration of Low Carbon generators increases beyond 50%, the degree of sharing of Year Round circuits is assumed to linearly reduce for all classes of generation. The current methodology therefore applies the TNUoS tariff elements to all "Conventional" generators in the same way irrespective of whether they are classed as "Carbon" (low constraint cost impact due to low BM bid cost), or "Low Carbon" (High constraint cost impact due to high BM bid cost). This represents a defect because the ability of Conventional Carbon to share with Low Carbon plant actually increases as Low Carbon plant becomes more dominant. The existing charging methodology assumes exactly the opposite relationship and therefore provides incorrect and perverse locational incentives for Conventional Carbon generators within zones with a relatively high concentration of Low

Carbon generators.

Explaining the background to the defect

To understand this modification proposal, it is important to be clear regarding the following terms which have a specific technical definition within the existing charging methodology:

1. Technology type by dispatchability: Classed as either "conventional" or "intermittent" depending on whether they can be dispatched as firm, or non-firm respectively.

2. Technology type by bid price: Classed as either "carbon" or "low carbon" depending on whether they tend to exhibit low cost, or high cost balancing mechanism bid prices respectively due to their short-run marginal cost of generation.

These four classification types were created by CMP213 to enable TNUoS charges to better reflect the different costs to transmission network investment caused by different types of generator. The first classification type of "Conventional" versus "Intermittent" is used by the charging methodology to identify whether a generator can be dispatched on a firm basis, so identify whether or not it pays the Peak Security tariff element. The second classification type of "Carbon" versus "Low Carbon" is used by the charging methodology to adjust the degree of sharing by taking account of the level of diversity as defined by the concentration of "Low Carbon" generation. The table below describes the four potential plant classification combinations and also includes a list of which generation technology types are currently included within each category by the existing charging methodology:

		Technology type by bid price	
		"Carbon" (Assumed low cost BM bid price)	**"Low carbon"** (Assumed high cost BM bid price)
Technology type by dispatchability	**"Conventional"** (Firm dispatch, so pays Peak Security tariff)	**"Conventional Carbon":** CCGT, OCGT, Coal, pumped storage, CHP, biomass	**"Conventional Low Carbon":** Nuclear, hydro
	"Intermittent" (Not firm dispatch, so does not pay Peak Security tariff)	**"Intermittent Carbon"**: No technologies identified	**"Intermittent Low Carbon"**: Wind, PV, tidal, wave

Further detail regarding these four existing classification types is described below

<u>Characterisation by dispatchability</u>

- **"Conventional"** – Stations which are capable of dispatching on a firm basis to meet peak demand. These stations contribute to network flows within the ICRP Transport model Peak Security background, so these stations pay the Peak Security tariff element.

- **"Intermittent"** - Stations which are not capable of dispatching on a firm basis to meet peak demand because they are reliant on a weather dependent source of input energy. These stations do not contribute to network flows within the ICRP Transport model Peak Security background, so these stations do not pay the Peak Security tariff element.

Characterisation by bid price

- **"Carbon"** – This is the name used (for the purpose of CMP213) to identify a class of generating stations that comprises generation plant that is flexible in nature, can reduce/increase output driven by market price and transmission system needs and importantly has a material positive short run marginal cost. This plant type will tend to bid to the System Operator in the Balancing Mechanism to reduce production at a relatively low cost (positive bid price), so offering a relatively low cost solution to managing constraints.

- **"Low carbon"** - This is the name used (for the purpose of CMP213) to identify a class of generating stations with the purpose of including stations which tend to operate on a "must run" basis, so almost always generate when input energy is available or, for technical reasons are inflexible, irrespective of transmission system need; e.g. demand level. This plant type will tend to bid to the System Operator in the Balancing Mechanism to reduce production at a relatively high cost (low or negative bid price), so offering a relatively high cost solution to managing constraints.

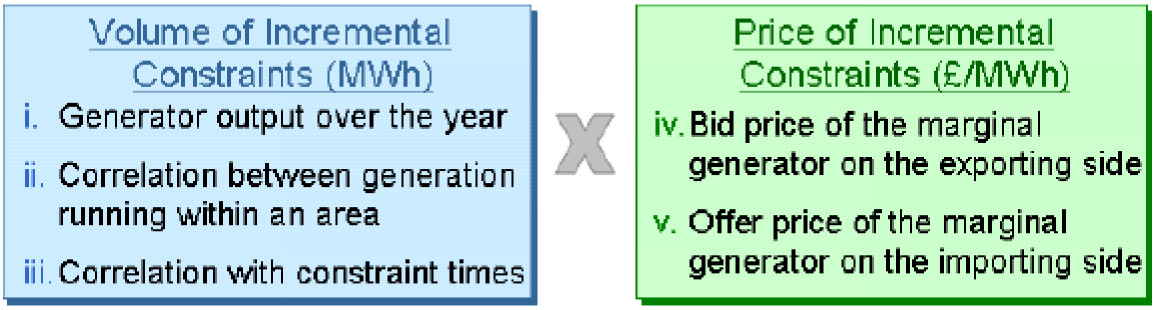
Detailed economic rationale behind the current methodology and this modification proposal

The economic justification for the current methodology was explained in the CMP213 Final CUSC Modification Report found at the following link : http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

The Workgroup report explains that following detailed analysis, the cost/benefit of sharing can be reflected by a generator's Annual Load Factor (ALF), and this approach was implemented in Ofgem's decision to apply a generator's ALF to their Year Round Shared tariff element. This relationship is described below:

> *4.14 From this ELSI based analysis the Proposer believed that a simple proxy for each generator's incremental impact on transmission network costs existed in the form of its ALF, and that this proxy could be incorporated into the existing ICRP approach in order to improve the cost reflectivity of this approach.*

The following illustration is from figure 5 of the CMP213 Workgroup report and explains the different components which drive transmission constraint costs. The "Volume of incremental constraints" is reflected by the station's ALF, while the "Price of incremental constraints" is reflected by the consideration of diversity using the classification of generators between "Carbon" and "Low Carbon" to split the Year-Round tariff between Shared and Not-Shared elements.



The CMP213 Workgroup report goes on to explain the circumstances and causes regarding why network sharing may reduce so that it becomes no longer appropriate to apply the ALF discount. This was described as occurring in zones with a relatively high proportion of Low Carbon generation for the following reason:

> *"4.21 …low carbon plant is more expensive to bid off* ***<u>than carbon plant, which generally has a lower bid price (close to marginal bid price), and is cheaper to constrain off."</u>*** [emphasis added]
>
> *"4.22 The linear relationship between load factor and incremental constraint costs breaks down* ***<u>when bids cannot be taken from plant at close to wholesale marginal price</u>****, and are taken from low-carbon plant instead."* [emphasis added]

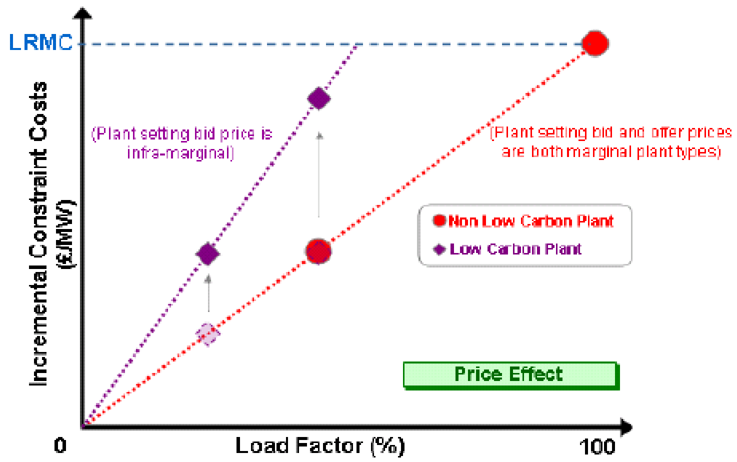


Figure 7 – Divergence in the linear relationship between low carbon and non low carbon plant

It is clear that the CMP213 Workgroup report acknowledged that the reduction in sharing and associated breakdown of the linear relationship with the ALF only occurs when bids can no longer be taken from Carbon Plant. Therefore, <u>it is the absence of Carbon plant which causes the higher constraint costs, not the presence of it</u>. The CMP213 Workgroup carried out analysis to illustrate the following describing the graph below:

> *"4.38 …The red dotted line shows the ideal linear relationship. Mapped against this are the impact of low carbon and carbon generation on this relationship as the percentage of low carbon generation in a zone increases. As the percentage of low carbon plant increases above 50% the cost of bids significantly increases. It follows in these circumstances that incremental low carbon plant increases constraint costs whilst* ***<u>incremental carbon plant reduces incremental constraint costs. This latter effect is because the volume of low carbon</u>***

<u>plant that runs provides cheaper bids than previously available in that transmission charging zone; i.e. the slope in that zone was previously steeper</u>.” [emphasis added]

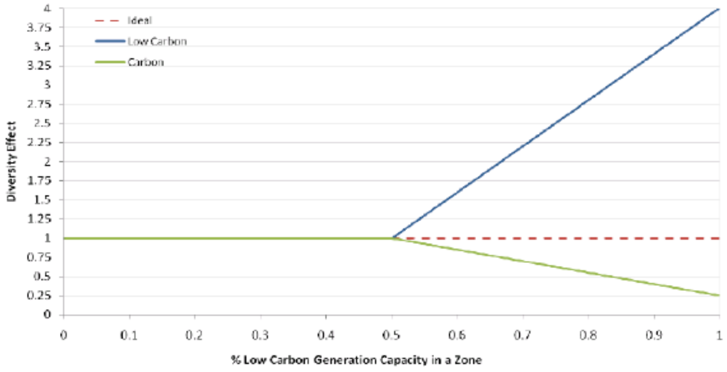


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

It follows that for a Conventional Carbon plant, the impact on constraint cost remains a function of their ALF <u>irrespective</u> of the proportion of low carbon plant it is sharing with because: 1) If in an half hour, the conventional carbon plant is generating, then it is available to be bid off, so a network constraint can be managed at a relatively low cost, so the Conventional Carbon generator is not causing a high constraint cost. 2) If in a half hour the Conventional Carbon generator is not generating, then it is also not causing a high constraint cost.

Clearly, Conventional Carbon plant do not cause the assumed reduction in sharing and they do not cause the assumed higher constraint costs (even in zones with a higher penetration of Low Carbon plant), <u>so it is a defect to charge them as if they do</u>.

Types of harm caused by the defect

If this defect is not corrected, then it will result in at least three key types of harm:

1. Firstly, competition is distorted by a non cost reflective economic disadvantage for Conventional Carbon generators which are located in zones with a high proportion of low Carbon generation.

2. Secondly, the defect will cause higher cost to customers than would otherwise be the case. This is because generators will face the incentive to make investment, or closure decisions which do not reflect the economic impact on the investment cost of the transmission network which they cause. This would result in an outcome which is less economically efficient at a higher cost to society and ultimately a higher cost to customers.

3. Thirdly, there is a locational security of supply risk. The current defect provides the perverse economic price signal that as more intermittent low carbon plant is built in a zone, then low load factor peaking plant experience higher TNUoS charges. This is a self reinforcing “death spiral” for low load factor peaking plant because as the charges

increase and low load factor peaking plant are encouraged to close, then this would further reduce the assumed degree of sharing, which would feed back to further increase the price signal for remaining low load factor peaking plant to close. If left uncorrected, then for that zone, the "death spiral" would result in a shortage of low load factor peaking plant and an increasing reliance on imported power to meet peak demand, which would result in an increasing risk to security of supply for customers in that zone.

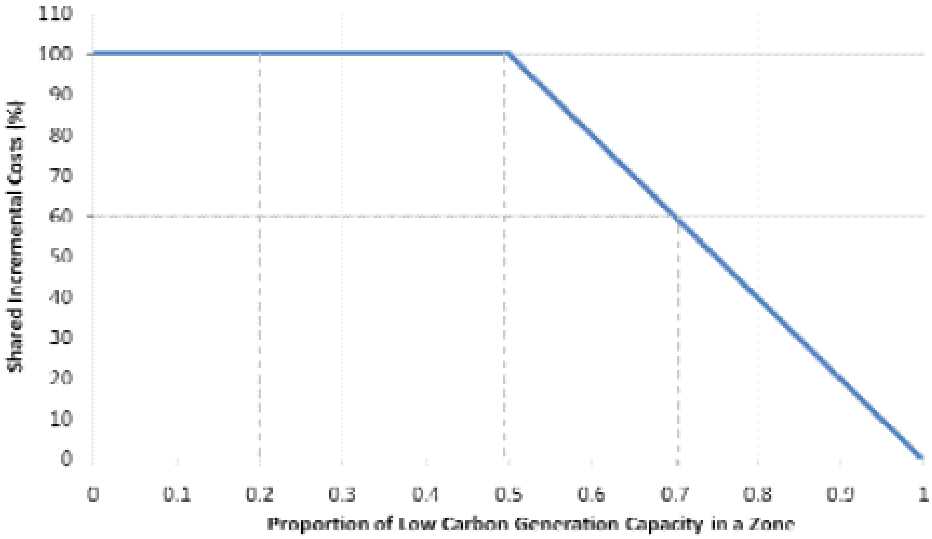
Description of the CUSC Modification Proposal

The proposal is that the charging methodology should be changed to more appropriately recognise that the different types of "Conventional" generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of "Conventional" generation pays. The change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator's ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements. This does not change the way the Year Round tariff is calculated and it does not change existing generator classifications, but it does change the formula by which the Year Round tariff is applied to different types of Conventional generator. This is described in more detail below.

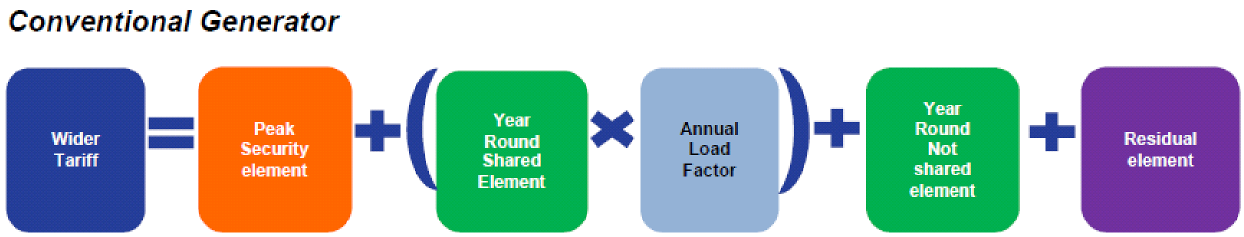
The element of the current tariff formula to be changed

In ICRP Transport model, the cost of Year Round circuits is allocated between Shared and Not Shared according to the relative share of "Low Carbon" compared with "Carbon" plant. The methodology assumes 100% sharing of circuits where the proportion of load flow of "Carbon" is between 100% and 50%. Beyond this point methodology assumes a straight line reduction in the degree of sharing from 50% until the proportion of load flow on the circuit accounted for "Carbon" plant declines to 0%. This is illustrated in the graph below.

Figure 18 from the CMP213 Workgroup report.

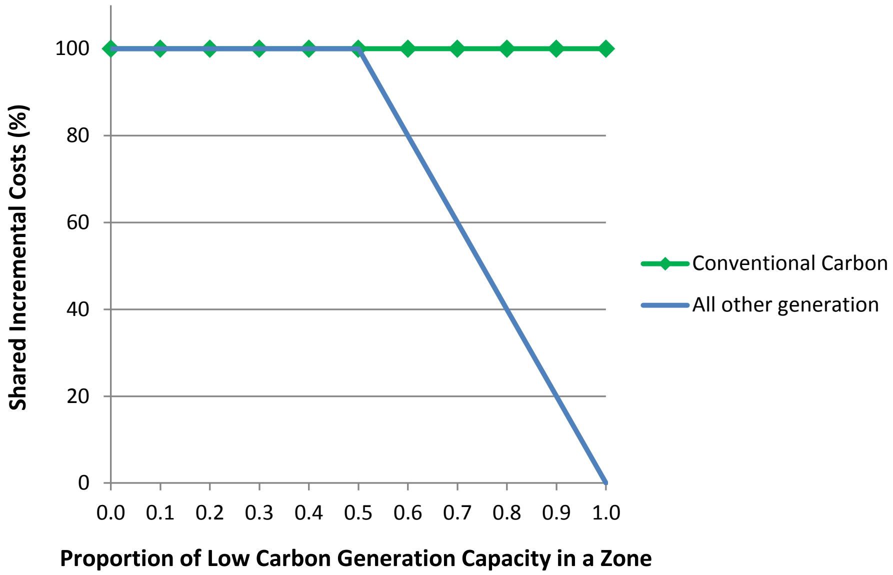


This principle is enacted through the current formula within the charging methodology where all generators (including Conventional Carbon generators) have their ALF applied to their Shared Year Round tariff element, but their ALF is not applied to their Not Shared Year Round tariff element. This is illustrated for Conventional Generators by the formula below taken from National Grid published Final TNUoS tariffs for 2016/17.



Proposed change to TNUoS tariff formula

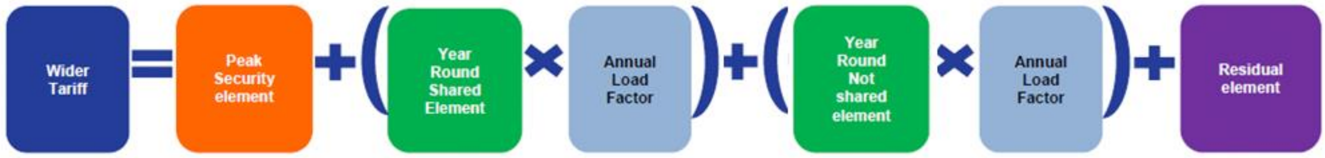
This modification proposes a change to the tariff formula relating to the way sharing is applied to Conventional Carbon generators so they continue to obtain 100% sharing of incremental costs irrespective of the proportion of low carbon generation capacity in a zone. This is illustrated by the graph below, which is a modified version of "figure 18" above.



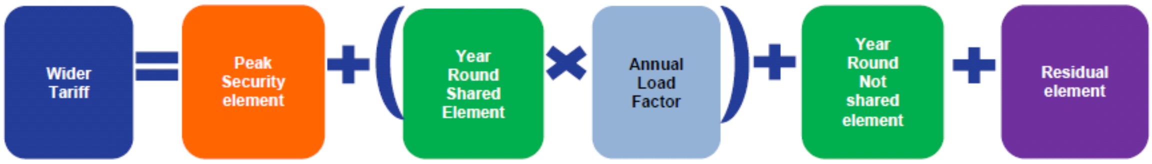
This modification proposal will recognise that even when the proportion of "Low Carbon" plant influencing a boundary is close to 100%, then any conventional carbon plant should have its ALF applied to the whole Year Round tariff (both Shared and Not-Shared elements of Year-Round).

This will require the existing tariff formula relating to "Conventional Generator" to be changed by splitting it into two parts: firstly "Conventional Generator – Carbon" and secondly "Conventional Generator - Low Carbon". For the avoidance of doubt, the existing tariff formula relating to "Intermittent Generator" is unchanged by this modification proposal. The proposed new tariff calculation formulas are illustrated below:

1) Adjusted tariff formula: "Conventional Generator – Carbon"
This represents a change from the existing "Conventional Generator" tariff formula since it applies the Generator's ALF to both its Not Shared Year Round as well as its Shared Year Round tariff elements.



2) Unchanged tariff formula: "Conventional Generator – Low carbon"
The tariff calculation remains the same as the current "Conventional Generator" tariff. It would be appropriate to give this unchanged tariff formula a new name to ensure it is clear which types of generation this applies to.



It is proposed that this new tariff calculation methodology would apply from the TNUoS charging year starting April 2017.

Impact on the CUSC

CUSC Section 14 – Part 2 – The Statement of the Use of System Charging Methodology, Section 1 – The Statement of the Transmission 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)

This is an optional section. You should select any Codes or state Industry Documents which may be affected by this Proposal and, where possible, how they will be affected.

Urgency Recommended: Yes / No

Yes.

Justification for Urgency Recommendation

This proposal should be treated as urgent as it is linked to an imminent date related issue; namely that bids to the capacity mechanism auction for 2017/18 and for 2020/21 could be significantly impacted. If the defect is not urgently addressed there may be a significant commercial impact on generator parties.

Self-Governance Recommended: Yes / No

No

Justification for Self-Governance Recommendation

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

Yes

Impact on Computer Systems and Processes used by CUSC Parties:

Details of any Related Modification to Other Industry Codes

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

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

Use of System Charging Methodology

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

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

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

☐ (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 (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:

In respect of (a) this modification will better facilitate effective competition in the supply of electricity because it will result in a more level playing field by correcting an existing TNUoS tariff defect which provides a non cost reflective economic disadvantage for a particular group of generators i.e. Conventional Carbon generators in a zone with a high share of low carbon generation.

In respect of (b) this modification will improve the cost reflectivity of Generation TNUoS charges.

Additional details

Details of Proposer: (Organisation Name)	SSE plc

Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or “National Consumer Council”)	CUSC Party
Details of Proposer’s Representative: Name: Organisation: Telephone Number: Email Address:	John Tindal SSE plc 01738 457308 John.tindal@sse.com
Details of Representative’s Alternate: Name: Organisation: Telephone Number: Email Address:	Garth Graham SSE plc 01738 456000 garth.graham@sse.com
Attachments (Yes/No): **If Yes, Title and No. of pages of each Attachment:**	

Contact Us

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

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

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

Submitting the Proposal

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

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

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

Annex 2 – CMP268 Terms of Reference

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Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP268 WORKSHOP

CMP268 aims to change the charging methodology to more appropriately recognise that the different types of “Conventional” generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of “Conventional” generation pays. The change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator’s ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements. This does not change the way the Year Round tariff is calculated and it does not change existing generator classifications, but it does change the formula by which the Year Round tariff is applied to different types of Conventional generator.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP268 ‘Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits’** was tabled by **SSE** at the CUSC Modifications Panel meeting on 29 July 2016.

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.

(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.

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. Reviewing CMP213
   b. Distribution impacts
   c. HVDC implications and links

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 **10** working days 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 **7 October 2016** for circulation to Panel Members. The final report conclusions will be presented to the Special CUSC Modifications Panel meeting on **11 October 2016**.

Membership

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

Role	Name	Representing
Chairman	John Martin	National Grid
National Grid Representative*	Damian Clough	National Grid
Industry Representatives*	John Tindal (Proposer)	SSE PLC
	James Anderson	Scottish Power
	Bill Reed	RWE
	Paul Jones	Uniper
	Paul Mott	EDF Energy
Authority Representatives	Andrew Malley	Ofgem
Technical secretary	Heena Chauhan	National Grid
Observers		

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

14. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The

agreed figure for CMP268 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 (Urgent) – Proposed Code Administrator Recommended Timetable

27 July 2016	CUSC Modification Proposal and request for Urgency submitted
29 July 2016	CUSC Panel meeting to consider proposal and urgency request
2 August 2016	Panel's view on urgency submitted to Ofgem for consultation
29 July 2016	Request for Workgroup members (5 Working days) (responses by 25 July 2016)
23 August 2016	Ofgem's view on urgency provided (15 Working days)
31 August 2016	Workgroup meeting 1
5 September 2016	Workgroup meeting 2
16 ~~9~~ September 2016	Workgroup Consultation issued (10 days)
30 ~~23~~ September 2016	Deadline for responses
TBC~~28 September~~ 2016	Workgroup meeting 3
TBC ~~3~~ October 2016	Workgroup meeting 4 (agree WACMs and Vote)
~~7 October 2016~~TBC	Workgroup report issued to CUSC Panel
TBC~~11 October 2016~~	Special CUSC Panel meeting to approve WG Report

Post Workgroup modification process

13 October 2016	Code Administrator Consultation issued (10 Working days)
27 October 2016	Deadline for responses
1 November 2016	Draft FMR published for industry comment (3 Working Days)
4 November 2016	Deadline for Industry comments
1 November 2016	Draft FMR circulated to Panel
8 November 2016	Special CUSC Panel meeting for Panel recommendation vote
10 November 2016	FMR circulated for Panel comment (2 Working day)
14 November 2016	Deadline for Panel comment
16 November 2016	Final report sent to Authority for decision
25 November 2016	Indicative Authority Decision due (7 working days)
30 November 2016	Implementation date

Annex 3 – Workgroup attendance register

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

Name	Organisation	Role	31/08/2016	05/09/2016	08/09/2016
John Martin	National Grid	Chair	A	X	X
Ryan Place	National Grid	Chair	X	A	A
Heena Chauhan	National Grid	Technical Secretary	A	A	A
John Tindal	SSE	Proposer	A	A	A
Damian Clough	National Grid	Workgroup member	A	A	A
Bill Reed	RWE	Workgroup member	D	A	A
Paul Jones	Uniper	Workgroup member	A	X	A
Paul Mott	EDF Energy	Workgroup member	D	A	A
James Anderson	Scottish Power	Workgroup member	D	A	D
Andrew Malley	Ofgem	Authority Representative	D	D	D

The Workgroup attendance register tracks the attendance of the Workgroup so that you can see how many people have attended when it comes to the Workgroup vote. In order to vote, Workgroup members need to have attended at least 50% of Workgroup meetings (either in person, teleconference or by sending an alternate) to be eligible to vote.

Annex 4 – Panel urgency letter

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Abid Sheikh
Industry Codes Manager
Ofgem
By email

2 August 2016

Dear Abid

CUSC Modifications Panel Views on Urgency for CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

On 26 July 2016, SSE raised CMP268, with a request for the proposal to be treated as an Urgent CUSC Modification Proposal. The CUSC Modifications Panel ("the Panel") considered CMP268 and the associated request for urgency at the CUSC Modifications Panel meeting held on 29 July 2016. This letter sets out the views of the Panel on the request for urgent treatment and the procedure and timetable that the Panel recommends.

CMP268 proposes to change the charging methodology to more appropriately recognise that the different types of "Conventional" generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of "Conventional" generation pays ideally ahead of the December Capacity Auction.

Request for Urgency
The Panel considered the request for urgency with reference to Ofgem's Guidance on Code Modification Urgency Criteria. The majority view of the Panel is that CMP268 does not meet these criteria and SHOULD NOT be treated as an Urgent CUSC Modification Proposal.

The Panel concluded that the Proposal did not relate to an imminent issue and although the proposal seeks to address an existing issue in the CUSC resulting from the implementation of CMP213, CMP268 will require careful consideration and is potentially more complex than envisaged by the Proposer and therefore not achievable within the timescales.

In the discussion, members of the Panel noted a few concerns over granting urgency, set out below;

- The Panel recognised analysis presented within the CMP213 Final Modification Report could be re-used by a Workgroup but agreed that this would need to be refreshed to bring it up to date.
- Using an urgent process holds an inherent risk of unintended consequences, which may arise due to there being insufficient time for all aspects of a Modification Proposal to be considered;
- There are complex issues identified by the Panel that need to be considered by a Workgroup.

Procedure and Timetable
Having decided to not recommend urgency to Ofgem, the Panel discussed an appropriate process for CMP268. The Panel agreed that the CMP268 proposal would require a Workgroup and careful consideration due to the potential implications against principles agreed during the implementation of CMP213.

The Panel agreed that CMP268 subject to Ofgem's decision on Urgency should follow the attached Code Administrators proposed timetable (Appendix 1). This was supported by majority view.

Please do not hesitate to contact me if you have any questions on this letter or the proposed process and timetable. I look forward to receiving your response.

Yours sincerely

Michael Toms
CUSC Panel Chair

Appendix 1 – Indicative Workgroup Timetable (Standard)

The following urgent timetable is following is indicative for CMP268 as per the recommendation of the Code Administrator

27 July 2016	CUSC Modification Proposal and request for Urgency submitted
29 July 2016	CUSC Panel meeting to consider proposal and urgency request
2 August 2016	Panel's view on urgency submitted to Ofgem for consultation
2 August 2016	Request for Workgroup members (5 Working days) (responses by 9 August 2016)
9 August 2016	Ofgem's view on urgency provided (5 Working days)
w/c 8 September 2016	Workgroup meeting 1
w/c 3 October 2016	Workgroup meeting 2
w/c 24 October 2016	Workgroup meeting 3
9 November 2016	Workgroup Consultation issued (15 days)
30 November 2016	Deadline for responses
w/c 5 December 2016	Workgroup meeting 4
w/c 19 December 2016	Workgroup meeting 5 (agree WACMs and Vote)
19 January 2017	Workgroup report issued to CUSC Panel
27 January 2017	CUSC Panel meeting to approve WG Report

Post Workgroup modification process

1 February 2017	Code Administrator Consultation issued (15 Working days)
22 February 2017	Deadline for responses
1 March 2017	Draft FMR published for industry comment (5 Working Days)
8 March 2017	Deadline for comments
23 March 2017	Draft FMR circulated to Panel
31 March 2017	Panel meeting for Panel recommendation vote
5 April 2017	FMR circulated for Panel comment (5 Working day)
12 April 2017	Deadline for Panel comment
14 April 2017	Final report sent to Authority for decision
24 May 2017	Indicative Authority Decision due (25 working days)
30 May 2017	Implementation date

Annex 5 – Ofgem view on urgency

Making a positive difference
for energy consumers

Michael Toms
CUSC Panel Chair
c/o National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

Direct dial: 020 7901 1857
Email: andrew.self@ofgem.gov.uk

Date: 23 August 2016

Dear Mr Toms,

CMP268 '*Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'* – decision on urgency

On 26 July 2016, SSE (the 'Proposer') raised Connection and Use of System Code (CUSC) modification proposal CMP268. This proposal seeks to change the Transmission Network Use of System (TNUoS) Charging methodology set out in the CUSC which, in the Proposer's view, fails to reflect the fact that different types of conventional generation cause different transmission network investment costs. The Proposer requested that CMP268 be treated as an Urgent CUSC Modification Proposal.

The CUSC Modifications Panel (the 'Panel') considered the Proposer's urgency request at its meeting on 29 July 2016. On 2 August 2016, the Panel wrote to inform us of its majority view that CMP268 should not be treated as urgent because the proposal did not relate to an imminent issue, would require careful consideration and was potentially more complex than envisaged by the Proposer.

In addition to the Panel's letter, we received information from the Proposer which is commercially sensitive and confidential, and was therefore not submitted to the Panel.

We considered both the Panel's and the Proposer's arguments. On balance, we have decided that CMP268 **should be progressed on an urgent basis**. We have set out our reasoning below.

The proposal

The Proposer considers that the current charging methodology fails to reflect the fact that different types of conventional generation, eg CCGTs[1] compared to nuclear, cause different transmission network investment costs to be incurred due to their different network sharing characteristics. In particular, it considers that the sharing factor in the Year Round tariff does not adequately reflect how conventional carbon generators drive costs in zones where low carbon generation penetration is greater than 50%.

[1] Combined Cycle Gas Turbine power stations

The Proposer therefore thinks that the current charging methodology is not cost-reflective for those plants. CMP268 would change the application of the sharing factor for conventional carbon generators to deal with this perceived defect.

The Proposer also claims that CMP268 should be treated as an urgent modification because the defect materially inhibits certain generators' ability to participate in the bids to the Capacity Market (CM) auction for 2017/18, which will take place in December this year, and for the 2020/21 CM auction. It argues that, as a result, if the defect is not urgently addressed, certain generators would be significantly commercially affected.[2]

Panel discussion

The Panel considered the request for urgency by reference to Ofgem's Guidance on Code Modification Urgency Criteria. The Panel's majority view is that CMP268 did not meet these criteria and should not be treated as an Urgent CUSC Modification Proposal.

The Panel concluded that the proposal did not relate to an imminent issue. While it sought to address an existing issue in the CUSC resulting from the implementation of CMP213[3], CMP268 requires careful consideration and is potentially more complex than envisaged by the Proposer. Full assessment of the proposal is therefore not achievable within urgent timescales.

Panel members had concerns about granting urgency. These were about refreshing any re-use of analysis presented within the CMP213 Final Modification Report, the inherent risk of unintended consequences with an urgent process, and concern that any workgroup assessing CMP268 would need to consider complex issues identified by the Panel.

Our views

We have considered the proposal, the Panel's views and the Proposer's arguments for urgency, and additional, commercially sensitive, information sent to us on a confidential basis.

We have assessed the request against the urgency criteria set out in our published guidance[4], in particular, whether the proposal is linked to an imminent issue or a current issue that, if not urgently addressed, may cause:

a. a significant commercial impact on parties, consumers or other stakeholder(s); or
b. a significant impact on the safety and security of the electricity and/or gas system.

We accept the Proposer's case and have decided that CMP268 should be granted urgent status because of the potential significant commercial impact on some power plants linked to the timing of the next two CM auctions in December 2016 and January 2017.

The Proposer argues that the current arrangements also result in a significant impact on safety and security. We do not accept this argument. We consider that the CM is designed to procure the amount of capacity needed to meet the reliability standard.

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[2] The Proposer's reasoning is set out in the CMP268 Proposal form at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP268/.

[3] Our decision on CMP213 is available here: https://www.ofgem.gov.uk/publications-and-updates/project-transmit-decision-proposals-change-electricity-transmission-charging-methodology . CMP213 was implemented on 1 April 2016.

[4] https://www.ofgem.gov.uk/system/files/docs/2016/02/urgency_criteria.pdf

We note the Panel’s concerns on the complexity of the proposal and the careful consideration needed, but we do not consider that these in themselves are reasons for rejecting urgency. We would however emphasise that, as for all proposals, we expect a sufficient level of analysis and stakeholder engagement to be undertaken in order to demonstrate whether or not CMP268 facilitates the Relevant Objectives better and is consistent with our principal objective and statutory duties.

For the avoidance of doubt, in granting this request for urgency, we have made no assessment of the merits of the proposal and nothing in this letter in any way fetters our discretion in respect of this proposal.

Next steps

The Panel’s letter contained only a non-urgent indicative timetable for progressing CMP268. The Panel should now present a new urgent timetable for our approval which takes account of the Proposer’s need for a timely decision but also allows for sufficient industry consultation and analysis, and for us to have sufficient time to reach a reasoned decision. This new timetable should be submitted to us no later than 26 August 2016.

CMP268 could have been raised sooner, given that, on 1 March 2016, the Government announced its proposal to bring forward the start of the CM delivery period by a year to 2017/18. We expect proposers who are seeking urgent status for CUSC Modification Proposals to raise their modifications more promptly and will take any delay into account when considering, under our Urgency Criteria, whether the matter is truly urgent.

Yours sincerely,

Andrew Burgess
Associate Partner, Energy Systems
Duly authorised on behalf of the Authority

Annex 6 – Panel recommended timetable following Authority urgency decision

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Abid Sheikh
Industry Codes Manager
Ofgem
By email

26 August 2016

Dear Abid

CUSC Modifications Panel Recommended Timetable for CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

On 26 July 2016, SSE raised CMP268, with a request for the proposal to be treated as an Urgent CUSC Modification Proposal. The CUSC Modifications Panel ("the Panel") considered CMP268 and the associated request for urgency at the CUSC Modifications Panel meeting held on 29 July 2016. This letter sets out the views of the Panel on the request for urgent treatment and the procedure and timetable that the Panel recommends.

CMP268 proposes to change the charging methodology to more appropriately recognise that the different types of "Conventional" generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of "Conventional" generation pays ideally ahead of the December Capacity Auction.

Request for Urgency
The Panel wrote to the Authority on 2 August 2016 which considered the request for urgency with reference to Ofgem's Guidance on Code Modification Urgency Criteria. The majority view of the Panel was that CMP268 did not meet these criteria and <u>SHOULD NOT</u> be treated as an Urgent CUSC Modification Proposal.

The Authority has since considered the views of the Panel along with confidential information received from the Proposer which had not been submitted to the Panel.

The Authority wrote to the Panel on 23 August 2016 and on balance has accepted the Proposer's case and has decided that CMP268 <u>SHOULD BE</u> granted urgent status because of the potential significant commercial impact on some power plants linked to the timing of the next two CM auctions in December 2016 and January 2017.

The Authority note the Panel's concerns on the complexity of the proposal and note that careful consideration is needed, but do not consider that these in themselves are reasons for rejecting urgency. They do however emphasise that, as for all proposals, a sufficient level of analysis and stakeholder engagement is expected to be undertaken in order to demonstrate whether or not CMP268 facilitates the Relevant Objectives better and is consistent with their principal objective and statutory duties.

The Panel's original letter contained only a non-urgent indicative timetable for progressing CMP268. At the Authority's request, the Panel is now presenting a new urgent timetable for your approval which takes account of the Proposer's need for a timely decision but also allows for sufficient industry consultation and analysis, and for sufficient time to reach a reasoned decision.

Please do not hesitate to contact me if you have any questions on this letter or the proposed process and timetable. I look forward to receiving your response.

Yours sincerely

Michael Toms
CUSC Panel Chair

Appendix 1 – Recommended Urgent Workgroup Timetable

The following urgent timetable is following is indicative for CMP268 as per the recommendation of the Code Administrator and the CUSC Panel

27 July 2016	CUSC Modification Proposal and request for Urgency submitted
29 July 2016	CUSC Panel meeting to consider proposal and urgency request
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9 September 2016	Workgroup Consultation issued (10 days)
23 September 2016	Deadline for responses
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3 October 2016	Workgroup meeting 4 (agree WACMs and Vote)
7 October 2016	Workgroup report issued to CUSC Panel
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1 November 2016	Draft FMR published for industry comment (3 Working Days)
4 November 2016	Deadline for Industry comments
1 November 2016	Draft FMR circulated to Panel
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10 November 2016	FMR circulated for Panel comment (2 Working day)
14 November 2016	Deadline for Panel comment
16 November 2016	Final report sent to Authority for decision
25 November 2016	Indicative Authority Decision due (7 working days)
30 November 2016	Implementation date