Stage 02: Workgroup Consultation

At what stage is this document in the process?

CMP282: 'The effect Negative Demand has on Zonal Locational Demand Tariffs'

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

Purpose of Modification: CMP282 seeks to amend how the DCLF model calculates Zonal Locational Demand tariffs so that the final locational zonal demand tariffs accurately reflect the underlying locational signals.

This document contains the discussion of the Workgroup which formed in July 2017 to develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 6 of this document.

Published on: 1 August 2017

Length of Consultation: 10 Working days

Responses by: 14 August 2017

High Impact:

Suppliers and Embedded Generators

As this modification aims to amend the Demand tariffs this modification will definitely affect Suppliers and Embedded Generators and potentially Transmission Connected Generators (depending on the final proposed solution).

Low Impact:

Transmission Companies.

Contents

Timetable

The Code Administrator recommends the following timetable:	
Workgroup Consultation issued to the Industry	31 July 2017
Modification concluded by Workgroup	w/c 28 August 2017
Workgroup Report presented to Panel	29 September 2017
Code Administration Consultation Report issued to the Industry	2 October 2017
Draft Final Modification Report presented to Panel	19 October 2017
Modification Panel decision	27 October 2017
Final Modification Report issued the Authority	13 November 2017
Decision implemented in CUSC	28 December 2017

Any questions?

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1 Format of this report and Terms of Reference

This report contains the discussion of the Workgroup which formed in July 2017 to develop and assess the proposal.

Section 2 (Original Proposal) and Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 5 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

The CUSC Panel detailed in the Terms of Reference the scope of work for the CMP282 Workgroup and the specific areas that the Workgroup should consider.

The table below details these specific areas and where the Workgroup have covered them or will cover post Workgroup Consultation.

The full Terms of Reference can be found in Annex 1.

Table 1: CMP282 ToR

Specific Area	Location in the report
a) Consider the practical implications of solution e.g. that data is available to National Grid to support the proposed solution and any system changes.	Section 4. Confirmed that no changes required to the billing system just changing the code used to calculate tariffs.
b) Consider the impact on the locational signals.	Section 4. Solution will not change the locational signals but just changing the way signals are translated into zonal tariffs.
c) Consider the interaction with other open Modifications.	Section 4. Workgroup consider the work taking place under CMP276 and the SQSS GSR016 Workgroup.

2 Executive summary

What is the defect?

For every location (node) on the Transmission System we model the impact on System flows of adding an extra 1MW of Generation at that location. If the signal is positive then adding 1MW at that location increases flows on the system. If negative then adding 1MW decreases flows on the System.

Nodes are grouped into Zones to try and add stability to tariffs. The locational signal for a zone is based on all the nodes within that zone. The nodal signal is weighted so that nodes with greater amounts of Demand or Generation than other nodes, impact on the Final Zonal tariff more than other nodes.

The mathematical calculation works correctly when all Demand nodes import. However, when a Demand node starts to Export, due to the mathematics this acts to inverse the nodal signal when calculating the Zonal Demand tariff. This modification aims to correct the defect so that locational signals are accurately reflected in the end Demand tariff

What is the impact of the Defect?

The defect has manifested itself in Demand Zone 1. Demand Zone 1 has seen an increase in its forecasted Demand Tariffs for 2018/19, whereas the underlying locational signals indicate that the Demand Tariff should be decreasing. Without this modification end consumers may see their Transmission Liability double (in Northern Scotland).

What is the proposal?

The defect manifests itself when nodes begin to Export. Therefore all proposals seek to change the mathematical calculation so that Exporting Nodes do not distort the final Zonal Demand Tariff.

- The Original Proposal achieves this by ignoring Exporting Nodes when calculating the Zonal Demand Tariff.
- Other proposals were evaluated, which also solved the defect. They achieved this by turning Exporting Nodes into Importing Nodes. Although the defect was solved, these proposals were dismissed by the workgroup as they solved the defect by manipulating data. The workgroup felt as a whole that Exporting Nodes should affect the Generation Tariff and if this cannot be achieved then they should be ignored.
- Following on from above, a solution where Exporting Nodes were not ignored and were taken into account in the Zonal Generation Tariff was also evaluated by the workgroup. This had the potential to be a better solution than the original as all nodes and their locational signal, affected either a Zonal Demand Tariff or a Zonal Generation Tariff, rather than being ignored. However a number of workgroup members noted that Generation at a node is scaled to match demand, with Generation Types scaled differently. Simply moving an Exporting Node and treating as Generation would solve one distortion whilst creating a new one, noting that there are Grid Code Modifications currently in progress regarding how to take into account Embedded Generation when planning Transmission Investment. If or when these modifications are implemented this

may potentially allow Exporting Nodes to be included within the Zonal Generation Tariff through a modification change.

- As the defect needs to be addressed as quickly as possible, the original proposal is the best way to achieve this.

How will the Proposal Change Demand Tariffs?

Table 7 within the document illustrates how the proposal will alter forecasted Demand Tariffs for 2018/19. Demand Zone 1 will see a decrease in its forecasted Tariffs as this zone contains by far the most Exporting nodes. Due to the tariff decrease less revenue is recovered from this zone, which therefore results in the Demand Residual increasing to make up for this reduction so all Demand Zones are affected.

As a Supplier what do I need to do?

The answer to this question is not a lot. Current TNUoS forecasts for 2018/19 are based on the baseline (i.e. include the defect). The proposal will not change the tariff structure or involve any changes to how demand is forecasted. As a Supplier please therefore take into account that forecasted Demand Tariffs for 2018/19 may alter due to this modification in the magnitude shown in Table 7. Timescales mean that any decision on this modification will be made before Final Demand Tariffs for 2018/19 become fixed.

What about previous years Tariffs?

The workgroup noted that the defect has always been there within the calculation. However for 2018/19 the number of Exporting GSPs has substantially increased, due to updated demand forecasts and new connections. The defect has therefore become material. The workgroup looked at how previous years tariffs would have changed if the proposed solution had been implemented for that charging year and found that the change to Demand Tariffs would have been minimal, whereas for 2018/19 the changes for Demand Zone 1 are material.

3 Original Proposal

Section 3 (Original Proposal) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 6 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

Defect

Final Zonal Locational Demand Tariffs most notably in North Scotland are distorted by nodes which are forecasted to Export at Peak when the Demand Zone is forecasted to Import or Import when the Demand Zone is forecasted to Export. The defect itself is contained within the calculation in the tariff part of the DCLF model which turns underlying locational signals into zonal weighted demand, and **not** the locational signals themselves within the Transport part of the DCLF model.

Why change

If the defect is not resolved Demand tariffs will not accurately reflect the costs imposed on the System by taking demand at that particular location. Where Demand tariffs do not reflect underlying costs, end users will pay more or less than what is required (if someone pays more, then someone will pay less) This creates inefficient investment signals and may go so far as to incentivises adverse behaviour to the investment signal.

The Locational signal, plus total demand at Peak determines how much revenue is required to be recovered from a particular demand zone. If the locational demand tariff increases, an increased amount of revenue is required to be recovered from that zone. If underlying demand has not actually changed then this results in Non-Half Hourly charges rising substantially more than Half hourly charges as NHH charges act as a Residual recovery mechanism for that zone. This explains why the forecasted NHH tariff for 18/19 rises more as a percentage change greater than HH tariffs in Zone 1.

What

When calculating the incremental cost for a particular location on the Transmission Network, National Grid uses the DCLF ICRP transport model. The DCLF model calculates the impact of adding 1MW of Generation at that particular location has on base flows under both the Peak and Year Round Scenarios.

When calculating the incremental impact of adding 1MW of Generation the model also calculates the impact of adding 1MW of Demand at the same location. The impact of adding 1MW of Demand is the inverse effect of adding 1MW of Generation. The locational tariff for Demand is therefore achieved by multiplying the nodal locational signal for Generation by -1 to calculate the locational tariffs for Demand.

Tariffs are calculated on a Zonal basis to provide stability. To calculate the zonal locational tariff, the locational signal for a particular node is weighted according to total Contracted Generation or net Demand for that zone. These are summated to create a weighted zonal average.

Nodes are weighted so that the zonal locational signals are not distorted by nodes with minimal amounts of demand and Generation, and revenues are collected in proportion to the amount of Generation and Demand at that node.

The table below hopefully illustrates the above and shows how nodal locational signals for a zone are turned into a final zonal locational tariff.

Node	LRMC	Demand	Weighted Demand	Weighted LRMC
1	1300	0	0%	0
2	1400	0	0%	0
3	1300	10	13%	162.5
4	1300	5	6%	81.25
5	1200	20	25%	300
6	1200	20	25%	300
7	1300	10	13%	162.5
8	1300	5	6%	81.25
9	1300	10	13%	162.5
10	1400	0	0%	0
		80		**1250**

The Weighted Zonal LRMC[1] is 1250. The LRMC's are calculated based on adding 1MW of Generation. They are subsequently turned into a Zonal Demand tariff by multiplying by **-1**, then by the Security Factor (1.8), then by the Expansion Constant (13.574496), with the final result divided by 1000 to turn the tariff into £/kW

I.e. 1250***-1***1.8*13.574496/1000 = -30.54

If Demand was actually Contracted Generation then the Zonal Generation tariff would be 30.54 (assuming we are calculating a tariff Peak) and not -30.54

If Embedded Generation was to connect at nodes 1, 4 and 8 this would reduce the net demand at that node. For the purposes of this example the amount of Embedded Generation is of sufficient quantity to turn demand at that node negative (i.e. Exporting).

[1] Long Run Marginal Cost (LRMC) is a locational signal. Further explanation is provided on page 16

Table 1

Baseline		
Node	LRMC	Demand
1	1400	-20
2	1500	0
3	1400	10
4	1400	-15
5	1300	20
6	1300	20
7	1400	10
8	1400	-15
9	1400	10
10	1500	0
[2]		**20**

As you can see the Nodal costs for Generation (LRMC) have increased in this zone as you would expect. If you add Generation (or reduce demand) at a node, the Nodal costs are likely to increase for all nodes in that zone due to an increase in flows. Node 1,4 and Node 8 have turned into negative demand.

The underlying locational signals have increased for Generation. As Demand is the inverse of Generation when calculating the Zonal Demand tariff you would expect the Locational Demand tariff to **decrease**. The table below shows the exact opposite happens when calculating the Locational Demand tariff.

Table 2

Baseline					
Node	LRMC	Demand	Weighted Demand		
1	1400	-20	-100%	-1400	
2	1500	0	0%	0	
3	1400	10	50%	700	
4	1400	-15	-75%	-1050	
5	1300	20	100%	1300	
6	1300	20	100%	1300	
7	1400	10	50%	700	
8	1400	-15	-75%	-1050	
9	1400	10	50%	700	
10	1500	0	0%	0	
		20		**1200**	-29.32

The Zonal Demand tariff now equals -29.32

*I.e. 1200****-1*****1.8*13.574496/1000 = -29.32*

This is an **increase** from the previous tariff of -30.54. So although the locational signal for Demand has decreased (LRMC's not weighted Demand) the demand tariff has gone up.

Why does this happen? Negative Demand is shown as a Negative number. When you multiply the LRMC's by Negative Demand the mathematics turn the LRMC's negative. To create a Demand tariff the Generation LRMCs are multiplied by -1 (A negative * negative = positive).

Negative Demand therefore has the effect of increasing the Locational Demand tariff when all the signals show that it should decrease further as there is less demand and more Generation.

For 18/19 the number of forecasted Exporting GSPs at Peak has increased to such an extent that the above defect is now having a material impact on Demand tariffs. The defect is exaggerated when Total Demand for a zone decreases closer to 0. When this occurs the weighted Nodal average for a node can significantly distort the Locational Demand tariff as demand at a node can be greater than the total demand for that zone (i.e. >100%).

There is a credible scenario where the Total Demand for a zone may become negative (exporting) as highlighted in table 3. In this scenario negative demand at a node actually creates an accurate locational signal, and it is positive demand nodes which work to distort the zonal locational demand tariff. The defect therefore is not negative Demand (exporting GSPs) but nodes which Export when the zone Imports and vice versa, and the underlying tariff calculations within the Tariff part of DCLF model.

Table 3

Node	LRMC	Demand	Weighted Demand			Node	LRMC	Demand	Weighted Demand		
1	1400	-20	-25%	-350		1	1400	-20	-25%	-350	
2	1500	-20	-25%	-375		2	1500	-20	-25%	-375	
3	1400	10	13%	175		3	1400	10	13%	175	
4	1400	-15	-19%	-262.5		4	1400	-15	-19%	-262.5	
5	1300	20	25%	325		5	1300	20	25%	325	
6	1300	20	25%	325		6	1300	30	38%	487.5	
7	1400	0	0%	0		7	1400	0	0%	0	
8	1400	-15	-19%	-262.5		8	1400	-15	-19%	-262.5	
9	1400	0	0%	0		9	1400	0	0%	0	
10	1500	-20	-25%	-375		10	1500	-20	-25%	-375	
		-40		**-800**	20.16			**-30**		**-637.5**	16.07

An increase in demand decreases the demand tariff which is incorrect.

The following section shows the legal text within the CUSC.

CUSC

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where
Gi = Generation zone
j = Node
$NMkm_{PS}$ = Peak Security Wider nodal marginal km from transport model
$WNMkm_{PS}$ = Peak Security Weighted nodal marginal km
$ZMkm_{PS}$ = Peak Security Zonal Marginal km
Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{j\,YR} = \frac{NMkm_{j\,YR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where
$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model
$WNMkm_{YR}$ = Year Round Weighted nodal marginal km
$ZMkm_{YR}$ = Year Round Zonal Marginal km
Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:
Di = Demand zone
Dem = Nodal Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

We would look to make changes to this calculation within the CUSC. Please note I have only included 15.40 as this clause includes definitions of the clauses within the formulae.

Why

If the defect is not resolved Demand tariffs will not accurately reflect the costs imposed on the System by taking demand at that particular location. Where Demand tariffs do not reflect underlying costs, end users will pay more or less than what is required (if someone pays more, then someone will pay less) This creates inefficient investment signals and may go so far as to incentivises adverse behaviour to the investment signal.

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How

If total nodal demand for a zone is positive, sum all positive demands. All Negative Demand is adjusted to 0. This creates an adjusted Total Zonal Demand. All positive demand is weighted against this new demand figure.

Baseline					
Node	LRMC	Demand	Weighted Demand	Weighted LRMC	
1	1300	0	0%	0	
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8	1300	5	6%	81.25	
9	1300	10	13%	162.5	
10	1400	0	0%	0	
		80		**1250**	-30.54

Baseline					
Node	LRMC	Demand	Weighted Demand		
1	1400	-20	-100%	-1400	
2	1500	0	0%	0	
3	1400	10	50%	700	
4	1400	-15	-75%	-1050	
5	1300	20	100%	1300	
6	1300	20	100%	1300	
7	1400	10	50%	700	
8	1400	-15	-75%	-1050	
9	1400	10	50%	700	
10	1500	0	0%	0	
		20		**1200**	-29.32

Proposed

Baseline						Proposal						
Node	LRMC	Demand	Weighted Demand	Weighted LRMC		Node	LRMC	Original Demand	Adjusted Demand	Weighted Demand		
1	1300	0	0%	0		1	1400	-20	0	0%	0.00	
2	1400	0	0%	0		2	1500	0	0	0%	0.00	
3	1300	10	13%	162.5		3	1400	10	10	13%	186.67	
4	1300	5	6%	81.25		4	1400	5	5	7%	93.33	
5	1200	20	25%	300		5	1300	20	20	27%	346.67	
6	1200	20	25%	300		6	1300	20	20	27%	346.67	
7	1300	10	13%	162.5		7	1400	10	10	13%	186.67	
8	1300	5	6%	81.25		8	1400	-15	0	0%	0.00	
9	1300	10	13%	162.5		9	1400	10	10	13%	186.67	
10	1400	0	0%	0		10	1500	0	0	0%	0.00	
		80		**1250**	-30.54			**40**	**75**		**1346.67**	-32.9

The change in the locational zonal demand tariff now reflects changes in the underlying locational demand signal (i.e. in the correct direction)

4 Proposer's solution

Section 4 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 6 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

If total nodal demand for a zone is positive, sum all positive demands. All Negative Demand is adjusted to 0. This creates an adjusted Total Zonal Demand. All positive demand is weighted against this new demand figure.

Baseline					
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6	1300	20	100%	1300	
7	1400	10	50%	700	
8	1400	-15	-75%	-1050	
9	1400	10	50%	700	
10	1500	0	0%	0	
		20		1200	-29.32

Proposed

Baseline					
Node	LRMC	Demand	Weighted Demand	Weighted LRMC	
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Proposal						
Node	LRMC	Original Demand	Adjusted Demand	Weighted Demand		
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5	1300	20	20	27%	346.67	
6	1300	20	20	27%	346.67	
7	1400	10	10	13%	186.67	
8	1400	-15	0	0%	0.00	
9	1400	10	10	13%	186.67	
10	1500	0	0	0%	0.00	
		40	75		1346.67	-32.9

The change in the locational zonal demand tariff now reflects changes in the underlying locational demand signal (i.e. in the correct direction)

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

No impact observed with the TCR. Does not appear to link in with any current ongoing modifications as no mods look to change the calculation of zonal weighted demand tariffs within the tariff model. All current mods 271/274/276 are not currently under Urgent timescales.

Consumer Impacts

Consumers in the North of Scotland, if tariffs are passed through by Suppliers will see an unjustified increase in their Electricity bills. If Suppliers choose not to pass this element directly on to the end consumer i.e. (Fixed tariffs) then this will harm competition. Although the defect currently affects consumers in the North of Scotland with the growth of Embedded Generation this could feasibly affect other parts of the country i.e. South West, Wales within 5 years.

5 Urgency Request

The Proposer requested that CMP282 be treated as an urgent proposal and should not be treated as self-governance as:

- To ensure that an approved CMP282 modification is implemented in advance of the draft publication of TNUoS tariffs; and
- If the defect is not resolved Demand tariffs will not accurately reflect the costs imposed on the System by taking demand at that particular location. Where Demand tariffs do not reflect underlying costs, end users will pay more or less than what is required (if someone pays more, then someone will pay less). This creates inefficient investment signals and may go so far as to incentivises adverse behaviour to the investment signal.

The Modification should not be treated as a self-governance due to its material impact on some parties.

The CUSC Modification Panel agreed by majority that CMP282 met the criteria for urgency and as such considered that it should be treated as an Urgent CUSC Modification Proposal[3]. The Panel concluded that there was a need for Urgency is to meet the Draft publication of TNUoS tariffs, recognising that although tariffs are finalised at the end of January, Industry feedback indicates that this is a key publication.

The Authority in its urgency decision letter confirmed that urgency should **not** be granted as both the urgent and standard timetables provided to the Authority would enable the modification to be implemented, if approved, ahead of final tariff setting in January 2018. As such, we do not consider a case has been made that the modification needs to be treated urgently to address the identified defect (if appropriate), or that it will therefore have a significant commercial impact on parties, consumers or other

A copy of Ofgem's Urgency decision letter can be found in Annex 2.

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[3] The CUSC Panel and Ofgem's views on Urgency for CMP282 is available using the following link: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP282/

6 Workgroup Discussions

The Workgroup convened two times to discuss the issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the CUSC Applicable Objectives. The Workgroup will in due course conclude these tasks after this consultation (taking account of responses to this consultation).

The Proposer presented the defect that they had identified in the CMP282 proposal and highlighted that the defect related to a feature in the Tariff Model that allowed for the mathematical impact of two negatives causing a positive number.

The Proposer confirmed that whilst the defect would have been present in previous Charging Year tariffs that the issue had only become apparent and visible as the level of Embedded Generation/demand reduction had increased in certain zones.

The Workgroup explored a number of aspects in its meetings to understand the implications of the proposed defect and solutions. The discussions and views of the Workgroup are outlined below.

1. What was the cause of the defect vs. impacts on the tariff methodology

When discussing the defect and why it was only becoming apparent now all the Workgroup was in agreement that the defect related to a feature of the Tariff Model and how the mathematics in the methodology used to calculate tariffs. All were in agreement that the defect as described resulted in the situation that when dividing two negative numbers the result is a positive number rather than there being an issue with the methodology. It was the view of the Workgroup that when the methodology was introduced it was not anticipated that GSPs would be netted exporting. The mathematical application results in the underlying signal not being reflective.

It was confirmed that the defect is not that there are exporting GSPs but what happens mathematically for zones that have negative demand when the Zonal Tariffs are calculated. For the avoidance of doubt it was confirmed that the LRMCs are correct.

Whilst the impact of the mathematical outcome was more prevalent in Scotland it could materialise elsewhere where Embedded Generation/demand reduction results in the zone being a net exporter. It was further noted by the Workgroup that because there is weighting and averaging on the nodes. Table 4 shows the tariffs for 2017/18 and forecasted tariffs for 2018/19.

Table 4

2017/18				June 2017 Forecast of 2018/19 Tariffs			
Demand				**Demand**			
Zone No.	**Zone Name**	**HH Zonal Tariff (£/kW)**	**NHH Zonal Tariff (p/kWh)**	**Zone No.**	**Zone Name**	**HH Zonal Tariff (£/kW)**	**NHH Zonal Tariff (p/kWh)**
1	Northern Scotland	29.577679	6.215608	1	Northern Scotland	52.136314	10.184611
2	Southern Scotland	30.480981	4.262747	2	Southern Scotland	33.996249	4.711528
3	Northern	39.223189	5.943493	3	Northern	43.488827	6.143092
4	North West	45.245665	5.878185	4	North West	50.229757	6.512836
5	Yorkshire	44.967107	5.978783	5	Yorkshire	49.861241	6.776159
6	N Wales & Mersey	46.791119	6.607274	6	N Wales & Mersey	51.571129	7.081867
7	East Midlands	47.889103	6.248796	7	East Midlands	52.800186	7.009019
8	Midlands	49.457444	6.426317	8	Midlands	54.548379	7.115274
9	Eastern	49.617070	7.095134	9	Eastern	54.385826	7.782534
10	South Wales	45.551887	5.775370	10	South Wales	50.953376	6.519821
11	South East	52.537577	7.475220	11	South East	57.217814	8.184488
12	London	54.969649	5.487378	12	London	59.695139	6.091993
13	Southern	53.405080	7.047920	13	Southern	58.571055	7.772624
14	South Western	51.955583	7.464813	14	South Western	58.296471	8.233390

2. Impact on previous Charging Year tariffs

The Proposer confirmed that whilst this defect had always been a feature of the calculation that the materiality associated in previous year tariffs had being small and as such the defect had not manifested itself. Furthermore it was confirmed that all Parties had paid the correct amount in relation to tariffs as the calculation was correct but the logic of the calculation requires amending under CMP282.

3. Long Run Marginal Costs (LRMCs)

The DCLF model calculates a locational signal (LRMCs) for each node (location) on the network. The model lists against each node the nodal incremental cost of adding 1MW of **Generation.** If the LRMC is a positive number then adding 1MW of Generation at that location increases flows on the System, If it's a negative number then adding 1MW of Generation at that location decreases flows on the System i.e. the South West of England. The impact of adding 1MW of Demand is the inverse of Generation. This is why the sum of weighted demand is then multiplied by -1 (turns the locational signal from Generation to Demand). In Demand Zone 1 the Nodal Incremental costs are negative. I.e. by taking demand in Scotland, flows are reduced on the System. The defect reduces this negative signal thus increasing the final Zonal Demand Tariff (Locational plus Residual).

4. Build-up of Demand Tariffs

Zonal Demand Tariffs contain both a Locational and Residual element. Table 5 and Table 6 on the following two pages illustrate how the Final Zonal Demand Tariff for 2017/18 and 2018/19 were derived. By comparing Table 5 and Table 6 the change in the Zonal Demand Tariff for Zone 1 can be seen to originate from the large change in the locational element of the charge (the defect).

When discussing HH charges it is more obvious how the locational element affects the Final HH Demand Tariff. However by following through the table you can see how the locational element flows through to the Zonal NHH tariff as well.

The purpose of these tables is therefore twofold. To illustrate how charges are derived, but also to show how the defect manifests itself in the final tariff, and that it is the result of the locational element and not other changes such as demand forecasts etc.

Table 5

TARIFFS 2017/18

Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Peak Security Transport Zonal Tariff (£/kW)	Peak Security Transport Zonal Revenue (£m)	Year Round Unadjusted Zonal Wtd Marginal (km)	Year Round Transport Zonal Tariff (£/kW)	Year Round Transport Zonal Revenue (£m)	Residual Tariff (£/kW)	Residual Zonal (£m)	Final Zonal Tariff (£/kW)	Final Zonal Revenue Recovery (£m)
Derivation of Zonal Demand HH Tariffs - Peak Secu						**Year Round**					**Final HH Demand Tariffs**	
1	Northern Scotland	0.923	-76.64	1.87	1.73	822.95	-20.11	-18.57	47.26	43.64	29.03	26.80
2	Southern Scotland	3.109	-0.92	0.02	0.07	710.26	-17.35	-53.96	47.26	146.94	29.93	93.05
3	Northern	2.267	109.32	-2.67	-6.06	242.23	-5.92	-13.42	47.26	107.14	38.67	87.67
4	North West	3.854	29.20	-0.71	-2.75	75.87	-1.85	-7.14	47.26	182.14	44.69	172.25
5	Yorkshire	3.566	105.43	-2.58	-9.19	11.04	-0.27	-0.96	47.26	168.52	44.41	158.37
6	N Wales & Mersey	2.350	74.35	-1.82	-4.27	-32.53	0.79	1.87	47.26	111.06	46.24	108.66
7	East Midlands	4.360	87.18	-2.13	-9.29	-90.30	2.21	9.62	47.26	206.06	47.34	206.39
8	Midlands	4.125	57.72	-1.41	-5.82	-125.02	3.05	12.60	47.26	194.93	48.91	201.71
9	Eastern	6.036	-42.63	1.04	6.29	-31.20	0.76	4.60	47.26	285.26	49.06	296.15
10	South Wales	1.657	253.13	-6.19	-10.25	-160.60	3.92	6.50	47.26	78.29	45.00	74.54
11	South East	3.711	-157.88	3.86	14.32	-35.48	0.87	3.22	47.26	175.39	51.99	192.93
12	London	4.112	-206.46	5.04	20.74	-86.43	2.11	8.68	47.26	194.32	54.42	223.75
13	Southern	5.179	-68.74	1.68	8.70	-160.13	3.91	20.27	47.26	244.78	52.85	273.75
14	South Western	2.436	38.22	-0.93	-2.27	-207.76	5.08	12.36	47.26	115.11	51.40	125.20
		47.684			**1.96**			**-14.33**		**2,253.60**		**2,241.23**

Derivation of Capped Zonal Demand NHH Tariffs

Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Chargeable HH Zonal Triad Demand (MW)	HH Zonal Triad Demand Revenue Recovery (£m)	Residual NHH Zonal Triad Demand (MW)	Required NHH Zonal Revenue Recovery (£m)	NHH Zonal 1600-1900 Demand (TWh)	NHH Zonal 1600-1900 Demand Share (%)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	923.39	- 668.025	-19.39	1,591.42	46.19	0.75	3%	6.14
2	Southern Scotland	3,109.18	641.726	19.21	2,467.45	73.85	1.76	7%	4.19
3	Northern	2,266.99	314.289	12.15	1,952.71	75.51	1.29	5%	5.87
4	North West	3,853.96	1,174.622	52.50	2,679.33	119.75	2.06	8%	5.80
5	Yorkshire	3,565.78	1,106.638	49.15	2,459.14	109.22	1.85	7%	5.90
6	N Wales & Mersey	2,349.89	519.724	24.03	1,830.17	84.62	1.30	5%	6.53
7	East Midlands	4,360.13	1,456.313	68.94	2,903.82	137.46	2.23	9%	6.17
8	Midlands	4,124.58	1,400.271	68.48	2,724.31	133.23	2.10	8%	6.35
9	Eastern	6,035.90	1,472.861	72.27	4,563.04	223.88	3.19	13%	7.02
10	South Wales	1,656.54	554.199	24.94	1,102.34	49.60	0.87	3%	5.70
11	South East	3,711.20	870.404	45.25	2,840.79	147.68	2.00	8%	7.40
12	London	4,111.70	2,194.260	119.41	1,917.44	104.34	1.93	8%	5.41
13	Southern	5,179.46	1,649.598	87.19	3,529.86	186.56	2.68	11%	6.97
14	South Western	2,435.66	540.175	27.77	1,895.49	97.43	1.32	5%	7.39
		47,684.35	**13,227.05**	**651.88**	**34,457.30**	**1,589.35**	**25.31**		

Table 6

2018/19 June Forecast

Derivation						Year Round					Final HH	
Zone	Zone Name	Total Charge Base: Triad (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Peak Security Transport Zonal Tariff (£/kW)	Peak Security Transport Zonal Revenue (£m)	Year Round Unadjusted Zonal Wtd Marginal (km)	Year Round Transport Zonal Tariff (£/kW)	Year Round Transport Zonal Revenue (£m)	Residual Tariff (£/kW)	Residual Zonal (£m)	Final Zonal Tariff (£/kW)	Final Zonal Revenue Recovery (£m)
1	Northern Scotland	0.928	-214.08	5.43	5.04	248.66	-6.30	-5.85	52.20	48.44	51.33	47.63
2	Southern Scotland	2.999	14.25	-0.36	-1.08	735.75	-18.66	-55.94	52.20	156.55	33.19	99.52
3	Northern	2.241	111.82	-2.84	-6.35	263.80	-6.69	-14.99	52.20	116.98	42.68	95.64
4	North West	3.685	25.76	-0.65	-2.41	84.01	-2.13	-7.85	52.20	192.36	49.42	182.11
5	Yorkshire	3.395	99.05	-2.51	-8.53	25.25	-0.64	-2.17	52.20	177.24	49.05	166.54
6	N Wales & Mersey	2.281	75.63	-1.92	-4.37	-18.77	0.48	1.09	52.20	119.07	50.76	115.78
7	East Midlands	4.228	82.62	-2.09	-8.86	-74.23	1.88	7.96	52.20	220.75	51.99	219.85
8	Midlands	3.960	49.26	-1.25	-4.95	-109.82	2.78	11.03	52.20	206.72	53.74	212.80
9	Eastern	5.829	-42.69	1.08	6.31	-11.45	0.29	1.69	52.20	304.32	53.58	312.32
10	South Wales	1.592	239.82	-6.08	-9.68	-158.59	4.02	6.40	52.20	83.08	50.14	79.81
11	South East	3.579	-139.68	3.54	12.68	-26.16	0.66	2.37	52.20	186.86	56.41	201.91
12	London	3.918	-199.64	5.06	19.83	-63.90	1.62	6.35	52.20	204.53	58.89	230.71
13	Southern	5.014	-70.18	1.78	8.92	-149.03	3.78	18.95	52.20	261.76	57.76	289.63
14	South Western	2.355	11.12	-0.28	-0.66	-219.50	5.57	13.11	52.20	122.95	57.49	135.39
		46.004			**5.89**			**-17.87**		**2,401.62**		**2,389.64**

Derivation									
Zone	Zone Name	Total Charge Base: Triad (MW)	Chargeable HH Zonal Triad	HH Zonal Triad Demand Revenue Recovery (£m)	Residual NHH Zonal Triad Demand (MW)	Required NHH Zonal Revenue Recovery (£m)	NHH Zonal 1600-1900 Demand (TWh)	NHH Zonal 1600-1900 Demand Share	NHH Zonal Tariff
1	Northern Scotland	927.92	- 530.025	-27.21	1,457.94	74.83	0.742763	3%	10.07
2	Southern Scotland	2,998.82	662.008	21.97	2,336.81	77.55	1.685257	7%	4.60
3	Northern	2,240.74	525.800	22.44	1,714.94	73.19	1.213144	5%	6.03
4	North West	3,684.81	1,166.911	57.67	2,517.90	124.44	1.943373	8%	6.40
5	Yorkshire	3,395.16	1,006.692	49.38	2,388.47	117.16	1.757455	7%	6.67
6	N Wales & Mersey	2,280.76	593.761	30.14	1,687.00	85.64	1.228252	5%	6.97
7	East Midlands	4,228.48	1,375.947	71.54	2,852.53	148.31	2.149586	9%	6.90
8	Midlands	3,959.84	1,353.543	72.74	2,606.30	140.06	1.999284	8%	7.01
9	Eastern	5,829.32	1,428.604	76.54	4,400.72	235.78	3.072886	13%	7.67
10	South Wales	1,591.52	526.254	26.39	1,065.27	53.42	0.833327	3%	6.41
11	South East	3,579.44	837.950	47.27	2,741.49	154.65	1.915153	8%	8.07
12	London	3,917.87	2,068.436	121.80	1,849.43	108.91	1.820474	8%	5.98
13	Southern	5,014.20	1,617.342	93.42	3,396.85	196.21	2.560509	11%	7.66
14	South Western	2,355.17	553.505	31.82	1,801.66	103.57	1.274955	5%	8.12
		46,004.03	**13,186.73**	**695.92**	**32,817.30**	**1,693.72**	**24.196417**		

5. Historic Tariffs

The Workgroup noted that the defect has always been within the Zonal Tariff calculation and asked the question why it had become a material defect for 2018/19 (Demand Zone 1) but had, had very minimal effect on tariffs previously. The National Grid representative explained the process of inputting data into the DCLF which calculates locational prices, and in particular Wk24 demand data. Each DNO provides National Grid a forecast of net demand at each Grid Supply Point (GSP) within their Distribution Network at System Peak (i.e. at the time of maximum demand on the GB System).This demand data is commonly known as Wk24 Demand data as it is received around Wk24 of the calendar year.

Wk24 Demand data is not provided by DNO's to National Grid for the purposes of setting locational tariffs. Its main purpose is for System Planning. However Wk24 demand data is an independent forecast of demand so it is used to set locational tariffs.

When comparing the forecasts of demand in Zone 1 for 2018/19 compared to 2017/18 there has been a 50% increase in Exporting GSPs, which results in negative weighted demand for that node when calculating the Zonal Locational Demand tariff. As described earlier in the report a negative weighted demand figure for a node distorts the locational signal.

The increase in Exporting GSPs is due to a number of factors such as new Embedded Generation, assessments of existing Generators output at Peak, as well as Demand Reductions.

As Total zonal demand reduces near to 0 and Embedded Generation increases, the weighted impact of negative demand also increases. This coupled with larger LRMCs (as demand reduces and Generation increases) amplifies the effect of the defect in Zone 1. Figure 1 to 3 show the effect of; increasing number of Exporting GSPs, Decreasing Total Demand within a zone, and changing LRMC's, with Figure 4 showing the effect on the locational demand tariff when all 3 combine. These examples highlight why the defect is now starting to have a material defect on tariffs.

Please remember that the examples illustrate simply Demand Zone 1 where the locational signal is negative. A reduced negative signal will increase the Final Zonal Demand tariff.

Figure 1 Increasing Exporting GSPs

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC		Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	50	150	0.125	18.75		1	-50	150	-0.125	-18.75
2	100	50	0.25	12.5		2	150	50	0.375	18.75
3	50	100	0.125	12.5		3	100	100	0.25	25
4	0	200	0	0		4	-50	200	-0.125	-25
5	200	100	0.5	50		5	250	100	0.625	62.5
	400			**93.75**			**400**			**62.5**
		Locational Demand		-93.75				**Locational Demand**		-62.5

Figure 2 Decreasing Demand

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	150	-0.125	-18.75
2	150	50	0.375	18.75
3	100	100	0.25	25
4	-50	200	-0.125	-25
5	250	100	0.625	62.5
	400			**62.5**
		Locational Demand		-62.5

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	150	-0.125	-18.75
2	100	50	0.25	12.5
3	50	100	0.125	12.5
4	-50	200	-0.125	-25
5	150	100	0.375	37.5
	200			**18.75**
		Locational Demand		-18.75

Figure 3 Changing Locational Signals

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	150	-0.125	-18.75
2	150	50	0.375	18.75
3	100	100	0.25	25
4	-50	200	-0.125	-25
5	250	100	0.625	62.5
	400			**62.5**
		Locational Demand		-62.5

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	-0.125	-25
2	150	50	0.375	18.75
3	100	100	0.25	25
4	-50	250	-0.125	-31.25
5	250	100	0.625	62.5
	400			**50**
		Locational Demand		-50

Figure 4 Combination of all 3

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	150	-0.125	-18.75
2	150	50	0.375	18.75
3	100	100	0.25	25
4	-50	200	-0.125	-25
5	250	100	0.625	62.5
	400			**62.5**
		Locational Demand		-62.5

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	-0.125	-25
2	100	50	0.25	12.5
3	50	100	0.125	12.5
4	-50	250	-0.125	-31.25
5	150	100	0.375	37.5
	200			**6.25**
		Locational Demand		-6.25

Table 8 shows the change in the locational element of 2017/18 tariffs if the Original Proposal had been in place. The change in locational tariffs for 2017/18 is a lot less pronounced than the change in 2018/19 tariffs between baseline and the original proposal.

As explained in the figures above the defect has been amplified for 2018/19 and is now a material defect. When assessing changes to tariffs, as part of the forecasting and tariff setting procress, it is very difficult to assess what the magnitude of change should be. Small changes in Contracted Generation or Demand at a node, can lead to large changes in tariffs, especially if circuits are lightly loaded and change the direction of flow; and vice versa; large changes in input data do not always cause large changes in tariffs. Therefore the direction of change is often usedas an important sense check rather than just magnitude. When comparing 2017/18 tariffs to 2016/17, the direction of change for zone 1 was in the same direction as all other zones. When comparing Zone 1 2017/18 to 2018/19 (Baseline), Zone 1's final Zonal Demand tariff goes in completely the opposite direction as all other zones, and in a different direction to the underlying locational signals.

6. Solutions

This section looks at the Proposers solution and other potential options to resolve the defect.

Proposer's solution: setting all negative demand to zero

The Proposer explained that having reviewed the output from the Transport model the negative demand in Scotland has the impact of increasing the locational tariff in the opposite direction to the indicated underling locational signals: When demand decreases in a zone or Generation increases this increases the Generation LRMCs. This therefore should decrease Demand LRMC's. This proposal therefore looks to treat negative demand nodes differently.

When calculating the Zonal Locational Tariff the calculation ignores negative demand (Exporting GSPs). As you can see this corrects the distortion in the locational signal.

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC		Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	-0.125	-25		1	0	200	0	0
2	100	50	0.25	12.5		2	100	50	0.25	12.5
3	50	100	0.125	12.5		3	50	100	0.125	12.5
4	-50	250	-0.125	-31.25		4	0	250	0	0
5	150	100	0.375	37.5		5	150	100	0.375	37.5
	200			**6.25**			**300**			**62.5**
		Locational Demand		-6.25				**Locational Demand**		-62.5

The Proposer confirmed that the solution would set any BMUs that have a negative demand to zero to ensure the correct locational signal. A demand node is a summation of all BMUs mapped to that GSP.

The view of the Workgroup was that the Proposer's original solution, if implemented, would prevent the locational signal being diluted further be setting negatives to zero when calculating the tariffs.

The workgroup Proposer noted that the positives of this solution is the simplicity of the proposal. It ignores demand information rather than manipulating data such as changing an Exporting Node to an Importing. Demand Nodes are weighted so that the Zonal Demand tariff is in proportion to the nodes creating the signal and the revenue then subsequently received is also in the same proportion. Exporting GSP's do not pay Demand tariffs therefore should not be included in the Zonal Demand tariff calculation.

The Workgroup then explored other options.

Option 1 Absolute Demand

All demand is treated as positive, so Exporting GSPs are turned into an Importing Node.

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC	Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	-0.125	-25	1	50	200	0.125	25
2	100	50	0.25	12.5	2	100	50	0.25	12.5
3	50	100	0.125	12.5	3	50	100	0.125	12.5
4	-50	250	-0.125	-31.25	4	50	250	0.125	31.25
5	150	100	0.375	37.5	5	150	100	0.375	37.5
	200			**6.25**		**400**			**118.75**
		Locational Demand		-6.25			**Locational Demand**		-118.75

The workgroup noted that this proposal solved the defect but achieved this by treating an exporting node and Importing. This was seen as manipulating data for the purposes of solving the defect, which was not acceptable. Under this solution the locational signal reduces significantly which would result in the Demand Tariff for this zone being rebased to 0.The positives of this option are that it is a simple proposal to implement and includes all locational signals for demand.

Option 2 Absolute Weighted Demand

The Workgroup and the Proposer considered whether the defect could be resolved by making all the weighted demand absolute (making all the negative demands into positive demand).

All weighted demand is treated as positive, so Exporting GSPs LRMC's are essentially turned into an Importing Node.

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC	Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	-0.125	-25	1	-50	200	0.125	25
2	100	50	0.25	12.5	2	100	50	0.25	12.5
3	50	100	0.125	12.5	3	50	100	0.125	12.5
4	-50	250	-0.125	-31.25	4	-50	250	0.125	31.25
5	150	100	0.375	37.5	5	150	100	0.375	37.5
	200			**6.25**		**200**			**118.75**
		Locational Demand		-6.25			**Locational Demand**		-118.75

As noted in Option 1 again this would involve manipulating data so was seen as not acceptable. However it does solve the defect and the locational tariffs are more in line with the original proposal. The positives of this option are that it is a simple proposal to implement and includes all locational signals for demand.

Option 3 Treat Exporting GSPs as Generation

The Workgroup noted that whilst the Proposer's original solution was the most pragmatic approach for resolving the demand tariff aspect that at a future date consideration should be made to investigate the generation tariffs.

Use of Gross Demand

In this option the Workgroup and the Proposer considered whether the defect could be resolved by using gross demand e.g. partially splitting Embedded Generation from demand. The view of the Workgroup was that this would have the advantage of solving the defect but ensuring that all locational signals for a zone Exporting and Importing are taken into account in either an Exporting (Generation) or Importing tariff (Demand).

The major blocker in undertaking this option however was how to treat Exporting nodes in terms of scaling. All Generation is currently scaled according to the SQSS. There are currently no rules regarding how to scale Embedded Generation. The Workgroup noted that this issue is being explored under the SQSS and that once the outcome of the work of the GSR16 Workgroup was known, that another modification to CMP282. In terms of timescales this is likely to be another year at least before any new rules are put in place. The defect is in place for 2018/19 so it is not appropriate to wait for other industry processes to run their course before trying to solve this defect.

7. Impact on tariffs for the Charging Year 2018/2019 (should the CMP282 Original be implemented) and materiality implications

The Workgroup as part of its analysis was presented with information on what the impacts would be on the 2018/2019 demand tariffs if the CMP282 original proposal was implemented.

In terms of the locational part of the Demand Tariff this will only change if the Demand Zone has Exporting GSPs. Those Demand Zones will see a reduction in the Locational Tariff and a subsequent reduction in the revenue required to be recovered from that zone.

Because less revenue is recovered this will have an impact on the Demand Residual, which will affect all Demand Zones.

Because the Demand Residual changes this also has a knock on effect on the Small Gens Discount as this is based on 25% of the Demand and Generation Residuals.

This is highlighted in Table 7 on the following page. Demand Zones with no Exporting GSPs should only see a change equivalent to the change in the Residual and Small Gens Discount.

NHH Tariffs will alter slightly differently between zones due to how NHH are set (i.e. residual Recovery).

Table 7

	June Forecast		Original Proposal				Absolute Demand				Absolute Weighted Demand			
Zone	HH	*NHH*	HH	**Change to June**	*NHH*	***Change to June***	HH	**Change to June**	*NHH*	***Change to June***	HH	**Change to June**	*NHH*	***Change to June***
1	52.14	*10.18*	29.01	-23.13	*5.64*	*-4.54*	25.42	-26.72	*4.94*	*-5.24*	-123.82	-175.96	*-24.36*	*-34.54*
2	34.00	*4.71*	34.24	0.25	*4.75*	*0.03*	34.11	0.11	*4.73*	*0.02*	35.05	1.05	*4.86*	*0.15*
3	43.49	*6.14*	43.97	0.48	*6.21*	*0.07*	44.04	0.55	*6.22*	*0.08*	45.99	2.50	*6.50*	*0.35*
4	50.23	*6.51*	50.60	0.37	*6.56*	*0.05*	50.56	0.33	*6.56*	*0.04*	53.69	3.46	*6.96*	*0.45*
5	49.86	*6.78*	50.38	0.52	*6.85*	*0.07*	50.48	0.62	*6.86*	*0.08*	53.86	4.00	*7.32*	*0.54*
6	51.57	*7.08*	52.09	0.52	*7.15*	*0.07*	52.19	0.62	*7.17*	*0.09*	55.57	4.00	*7.63*	*0.55*
7	52.80	*7.01*	53.32	0.52	*7.08*	*0.07*	53.42	0.62	*7.09*	*0.08*	56.80	4.00	*7.54*	*0.53*
8	54.55	*7.12*	55.06	0.52	*7.18*	*0.07*	55.17	0.62	*7.20*	*0.08*	58.55	4.00	*7.64*	*0.52*
9	54.39	*7.78*	54.90	0.52	*7.86*	*0.07*	55.01	0.62	*7.87*	*0.09*	58.38	4.00	*8.35*	*0.57*
10	50.95	*6.52*	51.47	0.52	*6.59*	*0.07*	51.57	0.62	*6.60*	*0.08*	54.95	4.00	*7.03*	*0.51*
11	57.22	*8.18*	57.73	0.52	*8.26*	*0.07*	57.84	0.62	*8.27*	*0.09*	61.21	4.00	*8.76*	*0.57*
12	59.70	*6.09*	60.21	0.52	*6.14*	*0.05*	60.31	0.62	*6.16*	*0.06*	63.69	4.00	*6.50*	*0.41*
13	58.57	*7.77*	59.09	0.52	*7.84*	*0.07*	59.19	0.62	*7.85*	*0.08*	62.57	4.00	*8.30*	*0.53*
14	58.30	*8.23*	58.81	0.52	*8.31*	*0.07*	58.92	0.62	*8.32*	*0.09*	62.29	4.00	*8.80*	*0.56*
Small Gens	0.81	*0.11*	0.82	0.01	*0.11*	*0.00*	0.82	0.01	*0.11*	*0.00*	0.87	0.06	*0.12*	*0.01*
Residual	52.20		52.71	0.51			52.82	0.61			56.14	3.94		

8. Impact on previous tariffs had CMP282 been approved and implemented

The Workgroup consider what the impacts would have been on previous tariffs had CMP282 Original Proposal (setting negative demand to zero) been approved and implemented. Table 8 shows the locational element of the tariff if the Original Proposal had been implemented in 2017/18.

Table 8

1718 Locational Element of Tariffs			1718 Tariffs Locational Elements if Original Proposal had been used		
Year Round	Peak	Zonal Total	Year Round	Peak	Zonal Total
-20.11	1.87	-18.24	-22.79	1.08	-21.71
-17.35	0.02	-17.33	-17.38	-0.01	-17.39
-5.92	-2.67	-8.59	-5.91	-2.70	-8.61
-1.85	-0.71	-2.57	-1.85	-0.71	-2.57
-0.27	-2.58	-2.85	-0.27	-2.58	-2.85
0.79	-1.82	-1.02	0.79	-1.82	-1.02
2.21	-2.13	0.08	2.21	-2.13	0.08
3.05	-1.41	1.64	3.05	-1.41	1.64
0.76	1.04	1.80	0.76	1.04	1.80
3.92	-6.19	-2.26	3.92	-6.19	-2.26
0.87	3.86	4.72	0.87	3.86	4.72
2.11	5.04	7.16	2.11	5.04	7.16
3.91	1.68	5.59	3.91	1.68	5.59
5.08	-0.93	4.14	5.08	-0.93	4.14

Table 9 shows the change in the 2018/19 Locational element of the tariff for the February forecast of tariffs and the Original Proposal for this change. The change in the locational element of the charge is far more pronounced than 2017/18.

Table 9

1819 Tariffs Baseline			1819 Tariffs Original		
Year Round	Peak	Zonal Total	Year Round	Peak	Zonal Total
-7.55	2.03	-5.51	-25.52	-1.22	-26.73
-18.65	-1.55	-20.20	-18.76	-1.64	-20.40
-6.41	-3.12	-9.53	-6.39	-3.17	-9.55
-1.99	-0.84	-2.83	-2.12	-0.86	-2.98
-0.44	-2.51	-2.95	-0.44	-2.51	-2.95
0.58	-2.12	-1.54	0.58	-2.12	-1.54
1.94	-1.65	0.29	1.94	-1.65	0.29
2.97	-1.41	1.56	2.97	-1.41	1.56
0.38	1.63	2.01	0.38	1.63	2.01
3.79	-5.99	-2.20	3.79	-5.99	-2.20
0.60	3.69	4.29	0.60	3.69	4.29
1.68	5.38	7.06	1.68	5.38	7.06
3.57	1.83	5.40	3.57	1.83	5.40
4.73	-0.84	3.89	4.73	-0.84	3.89

9. Workgroup evaluation of potential options

The examples are simple to implement apart from Gross Charging. The workgroup was provided a spreadsheet showing how the potential options would work in practice and the effect on Locational Tariffs. The overall effect on tariffs is shown in Table 7.

10. Potential Options 1 and 2

All members of the workgroup were in agreement that although these potential options achieved the correct result in reducing the Locational Demand tariff this was achieved by treating Exporting Nodes as Importing which was clearly not the correct thing to do, so was correcting one distortion by introducing a new one.

11. Option 3

Option 3 does exactly the same as the Original Proposal but goes one step further by not ignoring Exporting GSPs and including them in the calculation of Zonal Generation Locational Tariffs. A number of workgroup members said that this seemed a sensible approach in general. However they had a number of concerns with the approach of simply moving Exporting Demand and treating it as Generation.

12. Scaling

The Generation numbers in the Transport Model have firstly been scaled according to SQSS rules to match demand. By simply moving across a number from Demand and inserting in Generation, treats this Generation differently from other Generation types which, is discriminatory. The figure of -50 may be made up of a number of different Generation types, which would need to be scaled differently according to their Generation type. This proposal treats all Embedded Generation the same.

Another workgroup member commented that the number -50 is a net figure but may actually be made up of 100 units Embedded Generation and 50 units of demand so by moving across Exporting GSPs you are ignoring Embedded Generation at other nodes on the System which may not have negative demand.

The workgroup proposer was asked the question on how granular Wk24 Demand data is. The proposer stated that the DNO's are accurate in providing net demand figures as this can be taken from metering at the GSP, and this is the number used in the DCLF model. They do provide a number showing connected Generation at Peak. However the proposer did not feel that this number as well as Gross demand was of sufficient quality to set cost reflective charges. However they noted that they felt the accuracy of this number was improving year on year but this was a purely subjective point of view.

Workgroup members noted that there is an open SQSS modification GSR016, which is currently investigating how to scale Embedded Generation.

13. Future Work

This modification coupled with BSC Modifications P348 and P349 which will split Exporting and Importing meters within a Distribution zone will provide more data and set rules on how to deal with Embedded Generation. The workgroup noted that when these modifications are complete then Option 3 may well be a more complete solution.

14. Conclusion

It was agreed by the Workgroup that the defect does need to be resolved but that a pragmatic solution that resolves the defect and is simple and quick to implement should be the aim of the Workgroup. Changing Exporting demand to Importing (Options 2 & 3) was manipulating data for the sole purpose of resolving a defect and as such was discounted by the Workgroup.

It was the view of the Workgroup that the CMP282 Original Proposal would on balance, be the only acceptable solution. The Workgroup did note that the baseline should be re-assessed as and when data and rules are in place to allow a more complete solution.

15. Impacts on Suppliers and Supplier tariffs

In considering how a CMP282 could work, the Workgroup discussed what the impacts would be on setting the 2018/2019 demand tariffs and how these would be used by Suppliers in setting their tariffs. It was confirmed by the Workgroup that the original CMP282 provided a practical solution to allow for a decision by Ofgem to be made in time for the publication of draft tariffs.

16. Transitional Arrangements

The modification is intended to be fully implemented and not phased in. Demand Tariffs in Zone 1 are materially impacted for 2018/19. Making the required changes does have a consequential impact on all other demand zones through an increased residual. Due to the relatively small size of Demand Zone 1 compared to other Demand zones the change in the residual is within the magnitude of change between Quarterly Forecasts of tariffs. As there is only one option for this proposed modification this can be taken into account as a scenario when forecasting tariffs.

17. Legal text changes

The Workgroup discussed at a high level what the changes could be to Section 14 of the CUSC. The legal text changes will be developed after the Workgroup Consultation.

7 Workgroup Consultation questions

The CMP282 Workgroup is seeking the views of CUSC Parties and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and summarised below:

Standard Workgroup Consultation questions:

Q1: Do you believe that CMP282 Original proposal better facilitate the Applicable CUSC Objectives?

Q2: Do you support the proposed implementation approach?

Q3: Do you have any other comments?

Q4: Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider?

Please 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/CMP282/

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/

Views are invited upon the proposals outlined in this report, which should be received by **5pm** on **14 August 2017**. Your formal responses may be emailed to: cusc.team@nationalgrid.com

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.

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".

8 Relevant Objectives

Impact of the modification on the Applicable CUSC Objectives (Charging):	
Relevant Objective	Identified impact
(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;	Positive
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	Positive
(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*;	None
(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; and	None
(e) Promoting efficiency in the implementation and administration of the CUSC arrangements.	None
*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).	

<u>Charging Objective A</u>

Consumers in the North of Scotland, if tariffs are passed through by Suppliers will see an unjustified increase in their Electricity bills. If Suppliers choose not to pass this element directly on to the end consumer i.e. (Fixed tariffs) then this will harm competition. Although the defect currently affects consumers in the North of Scotland with the growth of Embedded Generation this could feasibly affect other parts of the country i.e. South West, Wales within 5 years.

<u>Charging Objective B</u>

Tariffs are meant to provide cost reflective signals. The tariffs currently for North of Scotland clearly do not reflect the underlying cost reflective signals. This may lead to increased Transmission expenditure funded by other users.

9 Implementation

Proposer's initial view:

The view of the Proposer was that CMP282 would require minimal system changes as the change would not change any billing systems as demand zones will stay the same. National Grid will need to implement changes to the DCLF model and the code within the model which does require expert Excel knowledge and testing.

10 Legal Text

The legal text will be developed by the Workgroup after the Workgroup Consultation.

11 Annex 1: CMP282 Terms of Reference

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP280 WORKGROUP

CMP282 seeks to amend how the DCLF model calculates Zonal Locational Demand tariffs so that the final locational zonal demand tariffs accurately reflect the underlying locational signals. aims to remove liability from storage facilities for Balancing Services Use of System (BSUoS) charges on imports.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP282 'The effect Negative Demand has on Zonal Locational Demand Tariffs'** raised by **National Grid** at the Modifications Panel meeting on 30 June 2017.

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

   Charging Applicable Objectives

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

   (b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard license 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. License under Standard Condition C10, paragraph 1; and

   (e) Promoting efficiency in the implementation and administration of the system charging methodology.

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

Scope of work

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

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

   a) Consider the practical implications of solution e.g. that data is available to National Grid to support the proposed solution and any system changes
   b) Consider the impact on the locational signals
   c) Consider the interaction with other open Modifications

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 **21 September 2017** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **29 September 2017**.

Membership

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

Role	Name	Representing
Chairman	Caroline Wright	Code Administrator
Technical Secretary	Heena Chauhan	Code Administrator
National Grid Representative/Proposer	Damian Clough	National Grid
Industry Representatives	Binoy Dharsi Charlie Friel Dan Hickman James Anderson Karl Maryon Nicola Fitchett Simon Lord Robert Longden Andy Colley	EDF Ofgem npower Scottish Power Haven Power RWE Engie (First Hydro nominated) Cornwall Energy (Fred Olsen nominated) SSE
Authority Representatives	Charlie Friel	OFGEM

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 CMP282 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

Proposed CMP282 Timetable

22 Jun 2017	CUSC Modification Proposal submitted
30 Jun 2017	CUSC Modification tabled at Panel meeting
22 Jul 2017	Request for Workgroup members (5 Working days)
14 Jul 2017	Workgroup meeting 1
18 Jul 2017	Workgroup meeting 2
21 Jul 2017	Workgroup meeting 3
24 Jul 2017	Workgroup Consultation issued (10 Working Days)
4 Aug 2017	Deadline for responses
w/c 14 Aug 2017	Workgroup meeting 4 **(WG review Consultation Reponses)**
w/c 28 Aug 2017	Workgroup meeting 5 (WG to agree options for WACMs)
21 Sep 2017	Workgroup report issued to CUSC Panel
29 Sep 2017	CUSC Panel meeting to discuss Workgroup Report

2 Oct 2017	Code Administrator Consultation issued (10 Working days)
13 Oct 2017	Deadline for responses
18 Oct 2017	Draft FMR published for industry comment (3 Working days)
23 Oct 2017	Deadline for comments
19 Oct 2017	Draft FMR circulated to Panel
27 Oct 2017	CUSC Panel Recommendation vote
27 Oct 2017	FMR circulated for Panel comment (3 Working days)
1 Nov 2017	Deadline for Panel comment
3 Nov 2017	Final report sent to Authority for decision
1 Dec 2017	Implementation date

Annex 2: Ofgem's Urgency CMP282 decision letter

ofgem
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 9951
Email: sean.hennity@ofgem.gov.uk

Date: 25 July 2017

Dear Mr Toms,

CUSC Modifications Panel views on Urgency for CMP282 'The effect negative demand has on zonal locational demand tariffs'

On 22 June 2017, National Grid (the Proposer) raised CMP282, with a request that it should be treated as an urgent CUSC Modification Proposal. CMP282 aims to amend how the 'DC Load Flow' (DCLF) model calculates Zonal Locational Demand tariffs so that the final locational zonal demand tariffs more accurately reflect the underlying locational signals.

On 3 July, the CUSC Modification Panel (the Panel) wrote to us requesting our decision on whether to grant urgency to CMP282. The Panel's view was that urgency should be granted for CMP282, this decision was supported by the majority of the Panel.

This letter confirms that we consider that modification proposal CMP282 should not be progressed on an urgent basis but on an accelerated timetable.

Background to the proposal

In February 2017, National Grid published forecast Transmission Network Use of System tariffs for charging years 2018/19 to 2021/22.[1] The document includes forecasts of half-hourly and non-half hourly demand tariffs for each transmission system demand zone. Beginning in charging year 2018/19, forecasts showed a significant increase in forecast tariffs in the North Scotland zone. Upon further investigation, the Proposer considers this increase was attributable to an unintended consequence of the model used to calculate demand locational tariffs rather than reflective of actual costs on the system.

The proposal

The Proposer considers that the current model for calculating the Zonal Locational Demand tariffs contains a defect. The Proposer considers that a defect with the model arises where demand at specific locations ('nodes') within a zone becomes negative. In these cases, the proposal states that negative demand has the effect of increasing the locational demand tariff when the underlying locational signals show that it should decrease it.

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

CMP282 aims to amend this defect so that the final zonal demand tariffs more accurately reflect the underlying locational signals. The Proposer does not consider the issue relates to the underlying locational signals themselves.

The Proposer notes that beginning in charging year 2018/19, the number of demand nodes forecast to export at Peak (ie have negative demand) is expected to increase to such an extent that they forecast the defect will have a material impact on demand tariffs. They consider that if the defect is not resolved, future demand tariffs will not accurately reflect the costs imposed on the system.

The Proposer considers that the identified defect could be addressed under a standard timetable, but has requested urgency to meet the Draft publication of TNUoS tariffs, expected in December 2017. Final tariffs are due to be published at the end of January 2018.

Panel Discussion

The Panel considered CMP282 and the associated request for urgency at its meeting held on 30 June 2017. The Panel wrote to us on 3 July with its recommendation on the urgency request made by the Proposer.

The majority view of the Panel was that CMP282 should be treated as urgent. However, the Panel expressed the view that there is likely to be more than one solution to the identified defect. The Panel set out, in an Appendix to its letter, both a proposed urgent and standard workgroup timetable for development of CMP282.

Our Views

In reaching our decision, we have considered the details contained within the proposal, the Proposer's justification for urgency and the views of the Panel. We have assessed the request against the criteria set out in Ofgem's published guidance,[2] in particular whether it is linked to "*an imminent issue or a current issue that if not urgently addressed may cause a significant commercial impact on parties, consumers or other stakeholder(s)".*

It is our view that both the urgent and standard timetables provided to the Authority would enable the modification to be implemented, if approved, ahead of final tariff setting in January 2018. As such, we do not consider a case has been made that the modification needs to be treated urgently to address the identified defect (if appropriate), or that it will therefore have a significant commercial impact on parties, consumers or other stakeholders.

For the avoidance of doubt, in not granting this request for urgency, we have made no assessment on the merits of the proposal and nothing in this letter in any way fetters the discretion of the Authority in respect of this proposal.

Yours sincerely,

Andrew Self
Head of Electricity Network Charging, Energy Systems
Signed on behalf of the Authority and authorised for that purpose

[2] The guidance document is available here: https://www.ofgem.gov.uk/publications-and-updates/ofgem-guidance-code-modification-urgency-criteria-0

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

Annex 3: CMP282 Attendance Register

A – Attended

X – Absent

O – Alternate

D – Dial-in

Name	Organisation	Role	14 July 2017	21 July 2017
Caroline Wright	National Grid	Chair	A/D	A/D
Heena Chauhan	National Grid	Technical Secretary	X	X
Damian Clough	National Grid	Proposer/NG Representative	A/D	A/D
Nicola Fitchett	RWE	Workgroup Member	X	A/D
Bill Reed	RWE	Workgroup Alternate	A/D	X
Binoy Dharsi	EDF	Workgroup Member	A/D	A/D
Dan Hickman	Npower	Workgroup Member	A/D	A/D
Simon Lord	Engie (nominated by First Hydro Company)	Workgroup Member	A/D	A/D

James Anderson	Scottish Power	Workgroup Member	X	X
Robert Longden	Cornwall Energy (nominated by Fred Olsen Renewables)	Workgroup Member	A/D	A/D
Karl Maryon	Haven Power	Workgroup Member	X	A/D
Charlie Friel	Ofgem	Workgroup Member	A/D	A/D
Andy Colley	SSE	Workgroup Member	A/D	A/D

