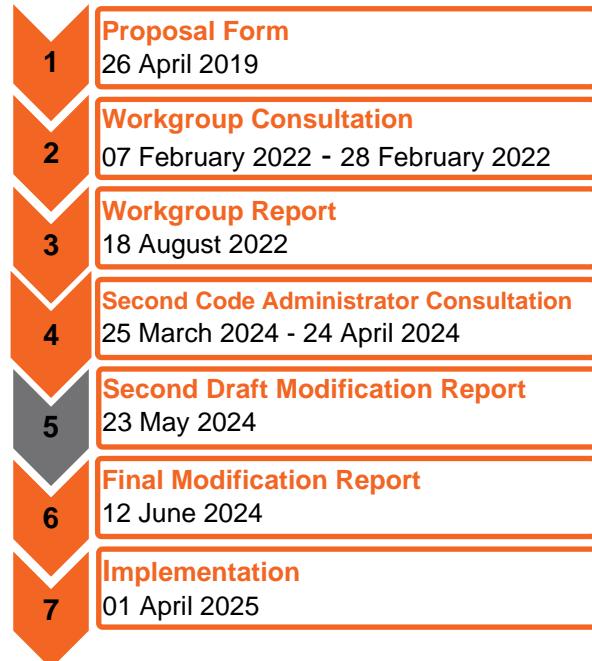


## Second Draft Final Modification Report

# CMP316: TNUoS Arrangements for Co-located Generation Sites

**Overview** Generation sites which comprise multiple technology types within one Power Station are termed “co-located.” This modification will develop a cost-reflective approach to allow the CUSC charging methodology to accommodate the growing number of such sites.

### Modification process & timetable



**Have 10 minutes?** Read our [Executive summary](#)

**Have 90 minutes?** Read the full [Second Draft Final Modification Report](#)

**Have 180 minutes?** Read the full Second Draft Final Modification Report and Annexes.

**Status summary:** The Second Draft Final Modification Report has been prepared for the recommendation vote at Panel.

**Panel recommendation:** The CUSC Panel will meet on 31 May 2024 to carry out their recommendation vote.

**This modification is expected to have a:** **Medium impact:** Co-located Generators / **Low impact:** The ESO

**Governance route** Standard governance modification assessed by a Workgroup and determined by the Authority.

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## Executive summary

Generation<sup>1</sup> sites which comprise multiple technology types within one Power Station are termed “co-located.” This modification will develop a cost-reflective approach to allow the CUSC charging methodology to accommodate the growing number of such sites.

### What is the issue?

Generation sites which comprise multiple technology types within one Power Station are termed “co-located” (which, in the context of the proposal, is also referred to as ‘Multi-Technology’). The TNUoS charging methodology does not adequately accommodate co-located generation sites. This is especially true for sites which have a mixture of technologies that fall into the two different charging categories (e.g., Conventional vs. Intermittent). The charging methodology within Section 14 needs to include a charging approach by which such sites can be recognised and charged consistently with the cost-reflective principles underpinning the broader TNUoS (Generator) Charging Methodology.

### What is the solution and when will it come into effect?

**Proposer’s solution:** The Proposer is seeking adding a new formula to the TNUoS charging methodology to calculate wider locational charges for ‘co-located’ or Multi-Technology Power Station. A proportion of the Power Stations Transmission Entry Capacity (TEC) will be assigned to each technology type, each with a separate Annual Load Factor (ALF). The solution utilises the current CUSC formula (CUSC 14.15.101) which is based on output per fuel/technology type across a Financial Year divided by the proportion of TEC (to be referred to, in the Original solution as ‘MTPSTEC’) for each technology type. The TNUoS charge(s) for each technology type will be calculated for each technology type individually and then summed to provide the total TNUoS charge for the whole (Multi-Technology) power station.

#### Implementation date:

01 April 2025

#### Summary of alternative solution and implementation date:

One alternative solution has been raised: WACM1 is different to the Original proposal in that:

- The tariff components for each technology type are calculated separately, where:
  - The Peak liability is pro-rated using Peak Installed TEC. A new term MTPSTECPk (Multi Technology Power Station TEC Peak) is introduced as the capacity to be used for calculating the peak charge.
  - The Not Shared Year Round is pro-rated using the ALF to give a scaled Not Shared Year Round liability. MTPSECS (Multi Technology Power Station Effective Capacity Scaled) and EALF (Effective ALF) are used for calculating the YRNS charge.
- ALF is calculated using the scaled TEC for the relevant technology type (rather than site TEC).

#### Implementation date:

01 April 2025

**Workgroup conclusions:** The Workgroup concluded by majority that the WACM1 better facilitated the Applicable Objectives than the Baseline.

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<sup>1</sup> Which includes both generation sites with more than one technology (including storage) or storage sites with more than one technology (including generation).

**Panel recommendation:** Panel will meet on 31 May 2024 to carry out their recommendation vote.

### What is the impact if this change is made?

According to the Proposer, a pro rata approach will provide greater cost-reflectivity to the charging arrangements for co-located sites – the Proposer believes this approach could be sufficiently generic to map onto other future changes in the network charging arena such that any broader developments resultant of (inter alia) Ofgem’s SCR into Access & Forward-Looking Charges would not be precluded by, or preclude, CMP316.

It is proposed that revisions are made to CUSC Section 14 to introduce a new formula which calculates the appropriate TNUoS charge per technology type for the Power Station.

### Interactions

It is understood that this modification does not have any interaction with other codes.

## What is the issue?

Generation sites which comprise multiple technology types within one Power Station are termed “co-located.” The TNUoS methodology does not adequately accommodate co-located generation sites. This is especially true for sites which have a mixture of technologies that fall into different charging categories (e.g., Conventional vs. Intermittent). Section 14 needs a methodology by which such sites can be recognised and charged consistently with the cost-reflective principles underpinning the broader TNUoS (Generator) Charging Methodology.

To avoid overlap with the scope of on-going Access and Forward-Looking Charges SCR, CMP316 does not aim to introduce a new access product nor modify an existing access product for shared access sites (e.g. two Generator Users sharing one point of connection).

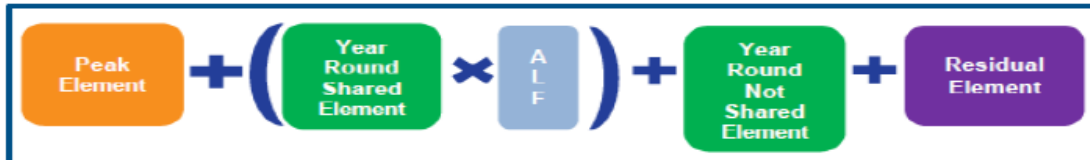
## Why change?

Currently, the TNUoS methodology assesses Power Station technology type and the ‘controllability’ of said technology type. Depending on the outcome, one of the following three formulas forms the basis for the wider TNUoS tariff calculation for that site (per 14.18.7 of CUSC)

### Conventional Carbon Generation:



### Conventional Low Carbon Generation:



### Intermittent Generation



For co-located sites, especially those which combine technologies in different charging categories i.e., intermittent generation or conventional low carbon, the current methodology cannot produce cost-reflective wider tariffs.

A pro rata approach will provide greater cost-reflectivity to the charging arrangements for co-located sites. The Proposer believes this approach could be sufficiently generic to map onto other future changes in the network charging arena, such that any broader developments resultant of (inter alia) Ofgem’s SCR into Access & Forward-Looking Charges would not be precluded by, or preclude, CMP316.

## What is the solution?

### Proposer's solution

#### Original

As the solution depends on pro rating TEC, the below should be used as the approach within the existing TNUoS charging methodology by which TEC is apportioned. The Proposed solution is to:

- For a Multi Technology Power Station, include a formula into CUSC Section 14.18
- For a Multi Technology Power Station the Power Station's TEC is allocated across the different technology types, specifically:

$$MTPSTEC_{is} = \frac{CAP_i}{\sum_{i=1}^n CAP_i} \times TEC_s$$

Where;

MTPSTEC<sub>is</sub> = Multi-Technology Power Station TEC for technology i at station s  
 CAP<sub>i</sub> = Capacity for technology i Maximum Capacity or chargeable capacity is then CAP<sub>i</sub> with MTPSTEC is station level

TEC<sub>s</sub> = TEC of Power Station as defined in the Connection Agreement  
 n = number of different technologies on site

When one of the wider tariffs is negative, "Chargeable MTPSTEC" is used instead, which is the same as the calculation above, but where:

- CAP<sub>i</sub> = Chargeable Capacity for technology I (average output of technology over the three settlement periods of highest output from November to end of February each year)
- TEC = Chargeable TEC for Power Station (average output of station over the three settlement periods of highest output from November to end of February each year)

#### WACM1

For the WACM1 solution, charges for each technology type are calculated separately by component, with a different calculation for each. The ALF is treated differently, proportioning on MTPSTEC rather than site TEC.

- MTPSTEC (Multi Technology Power Station TEC) is defined in the same way, and used for calculation of the Year Round Shared charge for each technology type, and the Adjustment charge
- MTPSTEC<sub>pk</sub> (Multi Technology Power Station TEC Peak) is introduced for calculating the Peak charge.
- EALF (Effective ALF) and MTPSECS (Multi Technology Power Station Effective Capacity Scaled) are introduced for calculating the Year Round Not Shared Charge

MTPSTEC<sub>PK</sub> is the sum of Maximum Capacity (MC) for each technology type as long the associated technology attracts a peak tariff component. (Where the associated technology does not attract a peak tariff component then the formula will consider that MC will be zero) Note MTPSTEC<sub>PK</sub> is capped at the MTPSTEC or technology MC, whichever is lower. MFPSTEC for each wider component (Peak Security (£/kW); Year Round Shared (£/kW); Year Round Not Shared (£/kW)), if Max Capacity for each technology does not attract peak security tariff, then it will be removed from the denominator of calculation. This will be capped at the max capacity for each technology, whichever is lower, and therefore MTPSTEC could be lower than TEC. This applies for Generation Charges (14.18) procedures.

$$MTPSTEC_{PK_{is}} = \min \left( \frac{CAP_i}{\sum_{i=1}^{m \neq n} CAP_i} \times TEC_s, CAP_i \right)$$

Where CAP<sub>i</sub> = Maximum Capacity for technology i to which peak security tariff applies  
 m = the number of technologies that attract peak security tariff  
 And m <= n

EALF (Effective ALF) is equal to 1 for all intermittent generation, and equal to ALF for all other technology types.

MTPSECS (Multi Technology Power Station Effective Capacity Scaled) uses the EALF to calculate an effective Capacity for charging, and scale to TEC.

$$MTPSECS_{is} = \min \left( \frac{EALF_i \times CAP_i}{\sum_{i=1}^m EALF_i \times CAP_i} \right) \times TEC_s, (EALF \times CAP_i)$$

For a Multi Technology Power Station, 'Chargeable Capacity' therein is based, on the MTPSTEC ( 14.18.17) is as per formula 14.15.

- ALFs are a measure of how frequently the station is operating over a year. ALFs are calculated from actual generation metering across a whole year (GWh) and the total TEC for the site. If the ALF is close to 1 then this indicates high usage. If the ALF is close to 0 then this indicates low usage. See CUSC 14.15.101 for formula. (Also see Example 7 for illustration of an ALF calculation).
- TEC is currently applied at station level. When MTPSTEC is introduced, this is, in effect, for charging purposes only and does not supersede or restrict station level TEC requirements. This therefore means that it is possible for a station, in operational timescales, to flex their TEC across technology types as long as the station level TEC is not breached. This flexing of MTPSTEC will be captured and be reflected by the technology specific MTPSALFs Whilst this proposed modification would impact upon TNUoS by splitting TEC across technology types, it does not propose to redefine or change the scope of these and so there is, according to the Proposer, no expected SCR impact. The Proposer does not intend (with this proposal) to introduce a new access product or modify an existing one.

The scope of CMP316 explicitly does not include shared access connections as these are within the scope of the Access and Forward-Looking charges SCR.

Approval and implementation of the modification will change the way that co-located generation sites are charged, and this approach will be reflected in an updated part within Section 14 of the CUSC. As such, compliance with this change will be mandatory (rather than voluntary) and intended implementation considers NGESO system impact and a transition period for industry participants and therefore recommends implementation to be effective 2025 starting on 1 April 2025. The solution for this modification will necessitate that each technology type for co-located generation sites will require its own BMU/metering. If each technology type for co-located generation sites does not have its own BMU/metering, then the existing TNUoS charging methodology approach will prevail; i.e. the site charge will continue to be based upon the predominant technology type as per the current charging arrangements in Section 14 of the CUSC. (Note that in practice the Workgroup do not currently see any conflict in determining the predominant technology type by using either TEC/installed capacity and they have not needed to define this further. This ambiguity could occur in future projects and this solution is looking to address and provide certainty for future projects.

## Workgroup considerations

This modification was originally raised in April 2019. Two Workgroup meetings were held in 2019 before the Workgroup was put on hold due to Panel Prioritisation of modifications.

The Workgroup then convened eleven times during 2021 and 2022.

As a considerable amount of time had passed since the first two Workgroup meetings, the solution has had minor updates, for example, the implementation date for the modification is now proposed to be 01 April 2025 instead of 1 April 2021 in the initial proposal. As new Workgroup members had joined the Workgroup, the first of the recommenced Workgroup meetings aimed at getting members up to speed on the updated modification.

To contextualise the number of co-located projects planned to come on to the NETS in the next few years, and therefore ascertain the size and impact of the defect, the Workgroup looked at the latest TEC register information provided by the Proposer below.

The latest TEC Register is always available on the ESO website:

[https://data.nationalgrideso.com/connection-registers/transmission-entry-capacity-tec-register/r/tec\\_register](https://data.nationalgrideso.com/connection-registers/transmission-entry-capacity-tec-register/r/tec_register)

A filter can be made on Plant Type, and co-located projects can be select as filter with more than one fuel type.

As can be seen, the number of co-located projects is increasing.



**CMP316: CO-LOCATED PROJECTS PUBLISHED ON LATEST TEC REGISTER**

Number of Co-located Projects on TEC Register (02/08/22)	Built	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Energy Storage System; PV Array (Photo Voltaic/solar)		4	12	16	21	18	15	17	16	1	3	123
CCGT (Combined Cycle Gas Turbine); Energy Storage System; OCGT (Open Cycle Gas Turbine)	1			1	2							4
Energy Storage System; Wind Onshore	2			1		1	3		2	1	1	11
Energy Storage System; PV Array (Photo Voltaic/solar); Wind Onshore						1		1	1			3
Energy Storage System; Gas Reciprocating			1	1								2
Energy Storage System; Reactive Compensation		1	1	2	1	2	1					8
Demand; Energy Storage System; PV Array (Photo Voltaic/solar); Reactive Compensation				1								1
PV Array (Photo Voltaic/solar); Wind Onshore								1				1
Energy Storage System; Wind Offshore	1											1
<b>Total</b>	<b>4</b>	<b>5</b>	<b>14</b>	<b>22</b>	<b>24</b>	<b>22</b>	<b>19</b>	<b>19</b>	<b>19</b>	<b>2</b>	<b>4</b>	<b>154</b>

Capacity (MW) of Co-located Projects on TEC Register (02/08/22)	Built	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
Energy Storage System; PV Array (Photo Voltaic/solar)		187	739	1,139	2,572	2,425	3,102	6,679	7,099	400	1,650	25,991
CCGT (Combined Cycle Gas Turbine); Energy Storage System; OCGT (Open Cycle Gas Turbine)	300			620	2,830							3,750
Energy Storage System; Wind Onshore	71			35		60	290		361	49	220	1,086
Energy Storage System; PV Array (Photo Voltaic/solar); Wind Onshore						60		400	600			1,060
Energy Storage System; Gas Reciprocating			300	450								750
Energy Storage System; Reactive Compensation		12	50	300	50	81	12					505
Demand; Energy Storage System; PV Array (Photo Voltaic/solar); Reactive Compensation				437								437
PV Array (Photo Voltaic/solar); Wind Onshore								180				180
Energy Storage System; Wind Offshore	90											90
<b>Total</b>	<b>461</b>	<b>199</b>	<b>1,089</b>	<b>2,980</b>	<b>5,452</b>	<b>2,626</b>	<b>3,404</b>	<b>7,259</b>	<b>8,060</b>	<b>449</b>	<b>1,870</b>	<b>33,849</b>

**Small Distributed Generators**

Both transmission and distribution connected generators with >100MW TEC are impacted by this modification as current payers of TNUoS. It was discussed that small distributed generation sites with <100MW of TEC would not be impacted through this modification as they do not currently pay TNUoS. However, the Workgroup agreed that they should consider how the solution would work if they were included, as they may pay TNUoS in the future. An assumption was made that if TNUoS charges are in the future extended to embedded generators with <100MW TEC that those TNUoS charges would be based on TEC (even though some currently don't have TEC). It was raised that if those sites were to pay TNUoS in future, a measure of installed capacity for each technology type, in addition to the total site TEC, would need to be provided for all sites <100MW to facilitate the proposed solution.

On 2 October 2021, Ofgem published a Call for Evidence on wider TNUoS reform. It was noted that this CMP316 work does interact with that Ofgem-lead work and the timeline for this modification should therefore coordinate with the wider work. Regarding the cost reflectivity principles reflected in the CMP316 Solution, the Workgroup considered that the principles of Transmit remain, i.e. TNUoS methodology as used today with the three Wider Generation Charging Categories (Conventional Carbon, Conventional Low Carbon and Intermittent) and allocation of fuel types to those categories remain fixed.

**The proposed pro-rata calculation**

The proposed solution looks to apportion TEC between different technology types on co-located sites using a new "Multi Technology Power Station" pro-rata formula.

## CAPI

The term 'CAPI' in the pro-rata formula requires installed capacity to be broken down by technology type to work out the proportions. The total installed capacity for each co-located site is proposed to be used for this, which is already provided to the ESO in each connection application form.

ESO representative explained that some existing co-located sites have provided CEC (Connection Entry Capacity) and this is stored within Data Registration Code (DRC). This data item was discussed to provide capacity for each technology type.

One Workgroup member shared concerns that individual plant CEC is not necessarily information which should be declared by the ESO. It was stated that the TEC register is currently published but CEC is not publicly known, and that there may be concerns in sharing site-specific CECs.

It was later agreed that Maximum Capacity as defined within the Grid Code will be used to provide capacity for each fuel/technology type and captured within the Connection Agreement Appendix C for all co-located sites.

The Proposer explained that a process would need to be established to ensure that all co-located sites have capacity for every technology type and a transition process establish to capture for existing sites too.

The Workgroup discussed that the 'MTPSTEC' for each technology type should be published, as currently the TEC register is public information.

It was suggested that the load factor should be applied to the installed capacity for the individual technologies before it is pro-rated. The Workgroup members approved this suggestion. Since each technology/fuel type for co-located generation sites will have its own BMU/metering then the ALF will be able to be applied separately to each as if they are standalone stations which improves cost reflectivity. If each technology type does not have its own BMU/metering, then there will be a combined ALF applied at the station level reflecting how TNUoS charges are calculated today. It was stated that ALFs are currently site specific, but they could be installed capacity specific.

It was suggested that there should be a post-event process for checking whether the pro-rata calculations are cost reflective, so that it could be checked whether the modification is carrying out its intended purpose.

Note that up to date ALFs and generic ALFs are published on ESO website:

Tables:

<https://www.nationalgrideso.com/uk/electricity-transmission/document/225821/download>

Report:

<https://www.nationalgrideso.com/uk/electricity-transmission/document/225826/download>

Please see Annex 7 for spreadsheet 'CMP316 Indicative Cost Tool.xlsx'

A draft end to end process for co-located generation examples has been worked through. The spreadsheet also provides a tool for the User to tailor to their situations with 'blue' areas of the spreadsheet for user input (e.g., TEC; installed capacity for technology; ALF; zone). The examples illustrate that the 'Parent Station A' holds the TEC. If this station has

co-located generation, then the calculations are made at the 'child station(s)' (technology) level for the purposes of TNUoS tariff setting, charging, calculation of ALFs, etc. Each 'child' station has an amount of MTSTEC, which is allocated pro-rata according to the proportion of the overall installed capacity that the 'child station's technology equates to. The calculations require that each child station must have at least one BMU. If this is not the case then the charging methodology today will prevail with the tariff reflecting the predominate technology type.

Please see summary tables and graphs for a comparison of monetary impact for each scenario. The figures are based on the 2021/22 TNUoS charges as if they were amended for the CMP316 proposed approach. The variance (in £) illustrates impact of proposed solution for CMP316 compared to the current TNUoS methodology for charging in place for 2021/22.

### **Analysis: The impact of implementation of CMP316 compared to charging methodology today**

Implementation of CMP316 will change the current TNUoS charging methodology for generation sites which comprise of multiple technology types within one Power Station. Implementation of this change to that methodology will change the way that sites are currently charged today - some sites TNUoS charges will be higher and others lower. In the Proposer's view it will mean that sites are recognised and charged consistently with the cost-reflective principles underpinning the broader Generator TNUoS Charging Methodology. The overall revenue collected from Generators via TNUoS will not change with this proposal as any resulting under/over recovery will be shared across all Users. The impact of CMP316 will vary dependent upon technology types, location, and technology type ALFs.

Eight sets of examples were discussed by the Workgroup. Please see below for the inputs used in those examples. These can be recreated within the spreadsheet 'CMP316 Indicative Cost Tool.xlsx'. Inputs are populated on tab 'USER INPUT z1' within the blue highlighted cells (ensuring that zone 1 is populated in cell B13). Costs are automatically calculated for all generation zones 1-27 and populated on separate tabs ('z2' to 'z27'). The costs (based on 2021/22 TNUoS tariffs) are summarised in a table and graph on tab 'Summary Table'. (Please see spreadsheet tab 'User Guide' for more details on using this Indicative Cost Tool.)

**Example 1:** Illustration of the solution where tariffs are negative, e.g. zone 26: Somerset and Wessex

A station with 300MW TEC and installed capacity for three technology types CHP/battery/solar 150/135/70 MW respectively. The child stations will be priced.

individually for each technology type to sum to the station TEC (127+114+59=300) and specific ALFs are used per child station as shown below.

MW	STATION A	Technology A1	Technology A2	Technology A3	STATION A
Installed Capacity		150.00	135.00	70.00	355.00
TEC	300.00				300.00
MTPSTEC		126.76	114.09	59.16	300.00
Fuel Type	CCGT_CHP	CCGT_CHP	Battery	Solar	0.00
Generation Zone	1	1	1		
Classification	Conv. Carbon	Conv. Carbon	Conv. Carbon	Intermittent	
Generic ALF	51.0635%	51.0635%	9.7926%	10.8000%	
Specific ALF	56.3731%				
Applied ALF	56.3731%	51.0635%	9.7926%	10.8000%	

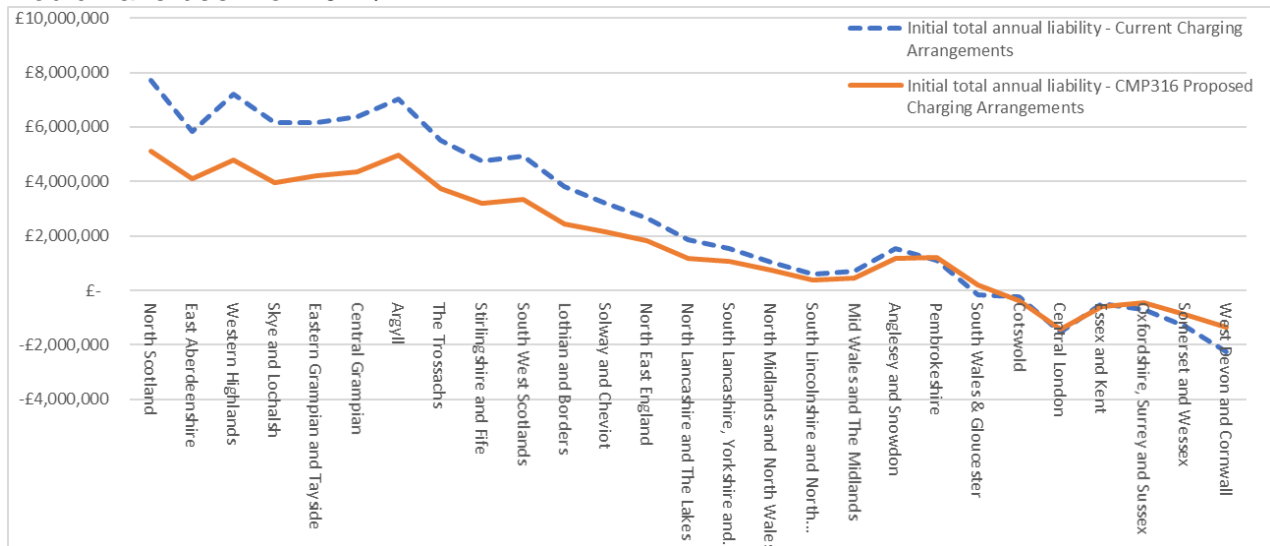


For completeness, the impact of the solution for this example station is also shown for all 27 generation zones in the table and chart below:

In the table, zones shaded green face lower charges for this example.

Zone No.	Zone Name	TEC	Generation Zone	Installed Capacity <sub>1</sub>	Installed Capacity <sub>2</sub>	Installed Capacity <sub>3</sub>	MFSSTEC <sub>1</sub>	MFSSTEC <sub>2</sub>	MFSSTEC <sub>3</sub>	Initial total annual liability - Current Charging Arrangements	Initial total annual liability - CMP316 Proposed Charging Arrangements	variance, higher charge under CMP316 proposed solution
1	North Scotland	300	1	150	135	70	127	114	59	£ 7,703,048	£ 5,093,524	-£ 2,609,524
2	East Aberdeenshire	300	2	150	135	70	127	114	59	£ 5,825,696	£ 4,087,622	-£ 1,738,074
3	Western Highlands	300	3	150	135	70	127	114	59	£ 7,206,343	£ 4,787,487	-£ 2,418,857
4	Skye and Lochalsh	300	4	150	135	70	127	114	59	£ 6,173,886	£ 3,957,337	-£ 2,216,549
5	Eastern Grampian and Tayside	300	5	150	135	70	127	114	59	£ 6,157,774	£ 4,201,881	-£ 1,955,892
6	Central Grampian	300	6	150	135	70	127	114	59	£ 6,388,551	£ 4,336,673	-£ 2,051,878
7	Argyll	300	7	150	135	70	127	114	59	£ 7,033,993	£ 4,951,897	-£ 2,082,096
8	The Trossachs	300	8	150	135	70	127	114	59	£ 5,526,328	£ 3,749,321	-£ 1,777,007
9	Stirlingshire and Fife	300	9	150	135	70	127	114	59	£ 4,748,126	£ 3,202,440	-£ 1,545,687
10	South West Scotland	300	10	150	135	70	127	114	59	£ 4,939,177	£ 3,336,854	-£ 1,602,323
11	Lothian and Borders	300	11	150	135	70	127	114	59	£ 3,806,573	£ 2,432,337	-£ 1,374,236
12	Solway and Cheviot	300	12	150	135	70	127	114	59	£ 3,198,344	£ 2,140,176	-£ 1,058,168
13	North East England	300	13	150	135	70	127	114	59	£ 2,665,429	£ 1,806,317	-£ 859,113
14	North Lancashire and The Lakes	300	14	150	135	70	127	114	59	£ 1,873,678	£ 1,172,945	-£ 700,733
15	South Lancashire, Yorkshire and Humber	300	15	150	135	70	127	114	59	£ 1,522,763	£ 1,078,535	-£ 444,228
16	North Midlands and North Wales	300	16	150	135	70	127	114	59	£ 1,017,787	£ 755,323	-£ 262,464
17	South Lincolnshire and North Norfolk	300	17	150	135	70	127	114	59	£ 576,847	£ 364,635	-£ 212,211
18	Mid Wales and The Midlands	300	18	150	135	70	127	114	59	£ 711,173	£ 459,757	-£ 251,415
19	Anglesey and Snowdon	300	19	150	135	70	127	114	59	£ 1,528,599	£ 1,157,776	-£ 370,823
20	Pembrokeshire	300	20	150	135	70	127	114	59	£ 1,086,783	£ 1,193,991	£ 107,208
21	South Wales & Gloucester	300	21	150	135	70	127	114	59	£ 177,866	£ 196,638	£ 374,504
22	Cotswold	300	22	150	135	70	127	114	59	£ 231,735	£ 383,557	£ 151,822
23	Central London	300	23	150	135	70	127	114	59	£ 1,520,646	£ 1,420,431	£ 100,215
24	Essex and Kent	300	24	150	135	70	127	114	59	£ 483,845	£ 592,018	£ 108,172
25	Oxfordshire, Surrey and Sussex	300	25	150	135	70	127	114	59	£ 691,646	£ 470,477	£ 221,169
26	Somerset and Wessex	300	26	150	135	70	127	114	59	£ 1,312,580	£ 892,275	£ 420,305
27	West Devon and Cornwall	300	27	150	135	70	127	114	59	£ 2,241,846	£ 1,370,820	£ 871,026

In the chart, the solid orange line shows the initial total annual liability under the CMP316 proposed solution. The dotted blue line shows charges by zone that the same site will face under current CUSC (non CMP316-amended) methodology, i.e. where the orange line is below the blue line then charges are lower under the CMP316 proposed solution than they would have been for 2021/22.



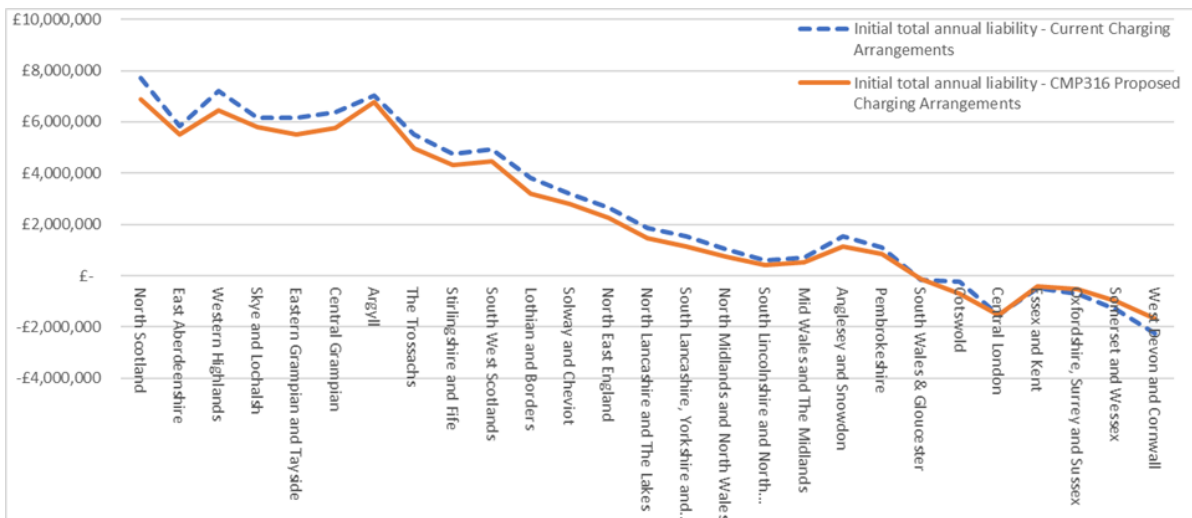
**Example 2:** Illustrates the combination of high ALF (CHP with 51% ALF) and low ALF (solar with 11% ALF) for each specific technology type within the CMP316 charging solution.



MW	STATION A	STATION A1	STATION A2	STATION A3	STATION A
Installed Capacity		250.00	80.00		330.00
TEC	300.00				300.00
MFSSTEC		227.27	72.73	0.00	300.00
Fuel Type	CCGT_CHP	CCGT_CHP	Solar		0.00
Generation Zone	1	1	1	1	
Classification	Conv. Carbon	Conv. Carbon	Intermittent		
Generic ALF	51.0635%	51.0635%	10.8000%		
Specific ALF	56.3731%				
Applied ALF	56.3731%	51.0635%	10.8000%		

MW	STATION A	Technology A1	Technology A2	Technology A3	STATION A
Installed Capacity		250.00	80.00		330.00
TEC	300.00				300.00
MTPSTEC		227.27	72.73	0.00	300.00
Fuel Type	CCGT_CHP	CCGT_CHP	Solar		0.00
Generation Zone	1	1	1		
Classification	Conv. Carbon	Conv. Carbon	Intermittent		
Generic ALF	51.0635%	51.0635%	10.8000%		
Specific ALF	56.3731%				
Applied ALF	56.3731%	51.0635%	10.8000%		

Zone No.	Zone Name	TEC	Generation Zone	Installed Capacity <sub>1</sub>	Installed Capacity <sub>2</sub>	Installed Capacity <sub>3</sub>	MFSSTEC <sub>1</sub>	MFSSTEC <sub>2</sub>	MFSSTEC <sub>3</sub>	Initial total annual liability - Current Charging Arrangements	Initial total annual liability - CMP316 Proposed Charging Arrangements	variance, higher charge under CMP316 proposed solution
1	North Scotland	300	1	250	80	0	227	73	0	£ 7,703,048	£ 6,876,092	-£ 826,956
2	East Aberdeenshire	300	2	250	80	0	227	73	0	£ 5,825,696	£ 5,493,338	-£ 332,357
3	Western Highlands	300	3	250	80	0	227	73	0	£ 7,206,343	£ 6,464,093	-£ 742,251
4	Skye and Lochalsh	300	4	250	80	0	227	73	0	£ 6,173,886	£ 5,789,589	-£ 384,297
5	Eastern Grampian and Tayside	300	5	250	80	0	227	73	0	£ 6,157,774	£ 5,517,323	-£ 640,451
6	Central Grampian	300	6	250	80	0	227	73	0	£ 6,388,551	£ 5,752,968	-£ 635,583
7	Argyll	300	7	250	80	0	227	73	0	£ 7,033,993	£ 6,773,751	-£ 260,242
8	The Trossachs	300	8	250	80	0	227	73	0	£ 5,526,328	£ 4,970,970	-£ 555,358
9	Stirlingshire and Fife	300	9	250	80	0	227	73	0	£ 4,748,126	£ 4,313,179	-£ 434,947
10	South West Scotlands	300	10	250	80	0	227	73	0	£ 4,939,177	£ 4,472,859	-£ 466,317
11	Lothian and Borders	300	11	250	80	0	227	73	0	£ 3,806,573	£ 3,212,079	-£ 594,495
12	Solway and Cheviot	300	12	250	80	0	227	73	0	£ 3,198,344	£ 2,814,347	-£ 383,997
13	North East England	300	13	250	80	0	227	73	0	£ 2,665,429	£ 2,242,608	-£ 422,821
14	North Lancashire and The Lakes	300	14	250	80	0	227	73	0	£ 1,873,678	£ 1,451,391	-£ 422,287
15	South Lancashire, Yorkshire and Humber	300	15	250	80	0	227	73	0	£ 1,522,763	£ 1,145,524	-£ 377,239
16	North Midlands and North Wales	300	16	250	80	0	227	73	0	£ 1,017,787	£ 748,311	-£ 269,476
17	South Lincolnshire and North Norfolk	300	17	250	80	0	227	73	0	£ 576,847	£ 411,375	-£ 165,472
18	Mid Wales and The Midlands	300	18	250	80	0	227	73	0	£ 711,173	£ 512,135	-£ 199,037
19	Anglesey and Snowdon	300	19	250	80	0	227	73	0	£ 1,528,599	£ 1,134,689	-£ 393,910
20	Pembrokeshire	300	20	250	80	0	227	73	0	£ 1,086,783	£ 830,771	-£ 256,012
21	South Wales & Gloucester	300	21	250	80	0	227	73	0	£ 177,866	£ 125,885	-£ 51,981
22	Cotswold	300	22	250	80	0	227	73	0	£ 231,735	£ 722,380	£ 490,645
23	Central London	300	23	250	80	0	227	73	0	£ 1,520,646	£ 1,520,261	£ 384
24	Essex and Kent	300	24	250	80	0	227	73	0	£ 483,845	£ 400,460	-£ 83,385
25	Oxfordshire, Surrey and Sussex	300	25	250	80	0	227	73	0	£ 691,646	£ 535,171	-£ 156,475
26	Somerset and Wessex	300	26	250	80	0	227	73	0	£ 1,312,580	£ 999,534	-£ 313,046
27	West Devon and Cornwall	300	27	250	80	0	227	73	0	£ 2,241,846	£ 1,682,455	-£ 559,391

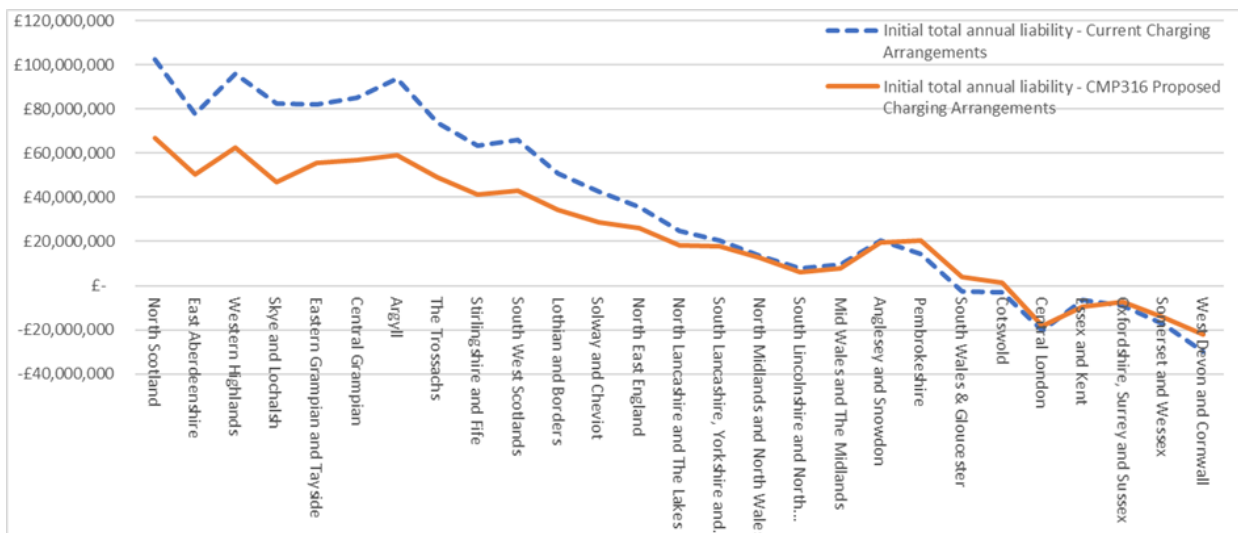


**Example 3:** Provides an example of a larger station with 3 technology types (Coal/Biomass/Battery)

MW	STATION A	STATION A1	STATION A2	STATION A3	STATION A
Installed Capacity		2200.00	1800.00	50.00	4050.00
TEC	4000.00				4000.00
MFSSTEC		2172.84	1777.78	49.38	4000.00
Fuel Type	Coal	Coal	Biomass	Battery	0.00
Generation Zone	1	1	1	1	
Classification	Conv. Carbon	Conv. Carbon	Conv. Carbon	Conv. Carbon	
Generic ALF	20.3859%	20.3859%	49.5396%	9.7926%	
Specific ALF	56.3731%				
Applied ALF	56.3731%	20.3859%	49.5396%	9.7926%	

MW	STATION A	Technology A1	Technology A2	Technology A3	STATION A
Installed Capacity		2200.00	1800.00	50.00	4050.00
TEC	4000.00				4000.00
MTPSTEC		2172.84	1777.78	49.38	4000.00
Fuel Type	Coal	Coal	Biomass	Battery	0.00
Generation Zone	1	1	1		
Classification	Conv. Carbon	Conv. Carbon	Conv. Carbon	Conv. Carbon	
Generic ALF	20.3859%	20.3859%	49.5396%	9.7926%	
Specific ALF	56.3731%				
Applied ALF	56.3731%	20.3859%	49.5396%	9.7926%	

Zone No.	Zone Name	TEC	Generation Zone	Installed Capacity <sub>1</sub>	Installed Capacity <sub>2</sub>	Installed Capacity <sub>3</sub>	MFSSTEC <sub>1</sub>	MFSSTEC <sub>2</sub>	MFSSTEC <sub>3</sub>	Initial total annual liability - Current Charging Arrangements	Initial total annual liability - CMP316 Proposed Charging Arrangements	variance, higher charge under CMP316 proposed solution
1	North Scotland	4000	1	2200	1800	50	2173	1778	49	102,707,306	66,859,434	-£ 35,847,872
2	East Aberdeenshire	4000	2	2200	1800	50	2173	1778	49	77,675,945	50,511,110	-£ 27,164,835
3	Western Highlands	4000	3	2200	1800	50	2173	1778	49	96,084,576	62,490,411	-£ 33,594,165
4	Skye and Lochalsh	4000	4	2200	1800	50	2173	1778	49	82,318,484	47,080,037	-£ 35,238,447
5	Eastern Grampian and Tayside	4000	5	2200	1800	50	2173	1778	49	82,103,649	55,545,478	-£ 26,558,171
6	Central Grampian	4000	6	2200	1800	50	2173	1778	49	85,180,674	56,772,733	-£ 28,407,941
7	Argyll	4000	7	2200	1800	50	2173	1778	49	93,786,573	59,168,991	-£ 34,617,582
8	The Trossachs	4000	8	2200	1800	50	2173	1778	49	73,684,370	49,156,003	-£ 24,528,368
9	Stirlingshire and Fife	4000	9	2200	1800	50	2173	1778	49	63,308,351	41,248,597	-£ 22,059,754
10	South West Scotlands	4000	10	2200	1800	50	2173	1778	49	65,855,691	43,219,969	-£ 22,635,722
11	Lothian and Borders	4000	11	2200	1800	50	2173	1778	49	50,754,313	34,269,580	-£ 16,484,733
12	Solway and Cheviot	4000	12	2200	1800	50	2173	1778	49	42,644,582	28,840,776	-£ 13,803,806
13	North East England	4000	13	2200	1800	50	2173	1778	49	35,539,060	26,003,799	-£ 9,535,261
14	North Lancashire and The Lakes	4000	14	2200	1800	50	2173	1778	49	24,982,378	18,370,364	-£ 6,612,014
15	South Lancashire, Yorkshire and Humbar	4000	15	2200	1800	50	2173	1778	49	20,303,506	17,760,683	-£ 2,542,823
16	North Midlands and North Wales	4000	16	2200	1800	50	2173	1778	49	13,570,487	12,769,476	-£ 801,011
17	South Lincolnshire and North Norfolk	4000	17	2200	1800	50	2173	1778	49	7,681,287	6,254,699	-£ 1,426,588
18	Mid Wales and The Midlands	4000	18	2200	1800	50	2173	1778	49	9,482,305	7,825,423	-£ 1,656,882
19	Anglesey and Snowdon	4000	19	2200	1800	50	2173	1778	49	20,381,324	19,448,028	-£ 933,296
20	Pembrokeshire	4000	20	2200	1800	50	2173	1778	49	14,490,444	20,328,524	£ 5,838,080
21	South Wales & Gloucester	4000	21	2200	1800	50	2173	1778	49	2,371,543	3,777,169	£ 1,405,626
22	Cotswold	4000	22	2200	1800	50	2173	1778	49	3,089,798	1,486,450	-£ 1,603,348
23	Central London	4000	23	2200	1800	50	2173	1778	49	20,275,276	18,426,220	-£ 1,849,055
24	Essex and Kent	4000	24	2200	1800	50	2173	1778	49	6,451,271	9,708,542	£ 3,257,271
25	Oxfordshire, Surrey and Sussex	4000	25	2200	1800	50	2173	1778	49	9,221,949	7,484,134	-£ 1,737,815
26	Somerset and Wessex	4000	26	2200	1800	50	2173	1778	49	17,501,071	14,434,659	-£ 3,066,412
27	West Devon and Cornwall	4000	27	2200	1800	50	2173	1778	49	29,891,280	22,191,465	-£ 7,699,815

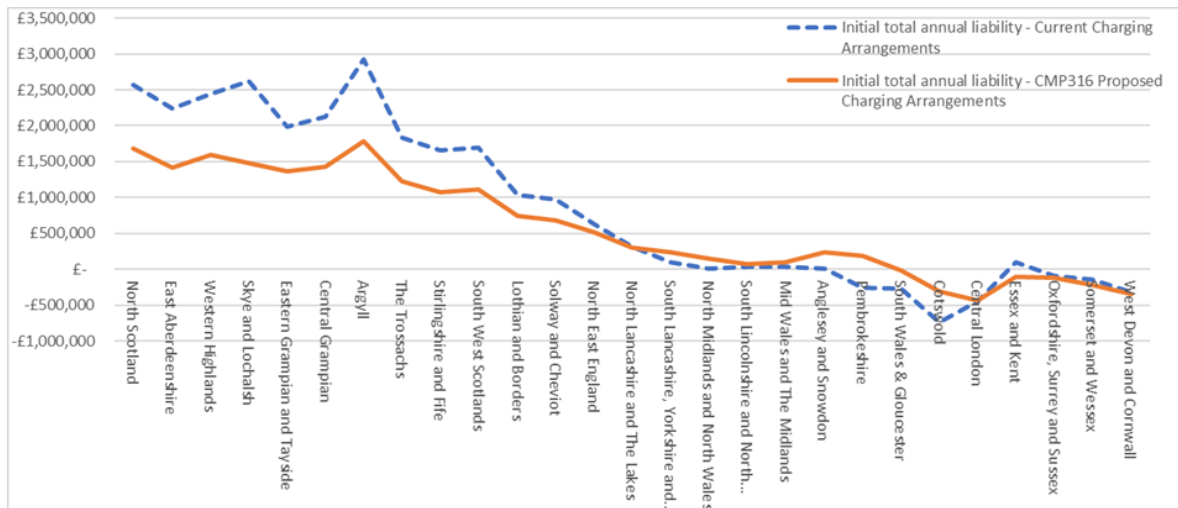


**Example 4:** Provides an example discussed by the Workgroup that was considered to be the most popular technology combinations consisting of onshore wind and battery. In this case the installed capacity is assumed to be near equal amounts.

MW	STATION A	STATION A1	STATION A2	STATION A3	STATION A
Installed Capacity		102.00	98.00		200.00
TEC	100.00				100.00
MFSSTEC		51.00	49.00	0.00	100.00
Fuel Type	Onshore_Wind	Onshore_Wind	Battery		0.00
Generation Zone	1	1	1	1	
Classification	Intermittent	Intermittent	Conv. Carbon		
Generic ALF	36.0719%	36.0719%	9.7926%		
Specific ALF					
Applied ALF	36.0719%	36.0719%	9.7926%		

MW	STATION A	Technology A1	Technology A2	Technology A3	STATION A
Installed Capacity		102.00	98.00		200.00
TEC	100.00				100.00
MTPSTEC		51.00	49.00	0.00	100.00
Fuel Type	Onshore_Wind	Onshore_Wind	Battery		0.00
Generation Zone	1	1	1		
Classification	Intermittent	Intermittent	Conv. Carbon		
Generic ALF	36.0719%	36.0719%	9.7926%		
Specific ALF					
Applied ALF	36.0719%	36.0719%	9.7926%		

Zone No.	Zone Name	TEC	Generation Zone	Installed Capacity <sub>1</sub>	Installed Capacity <sub>2</sub>	Installed Capacity <sub>3</sub>	MFSSTEC <sub>1</sub>	MFSSTEC <sub>2</sub>	MFSSTEC <sub>3</sub>	Initial total annual liability - Current Charging Arrangements	Initial total annual liability - CMP316 Proposed Charging Arrangements	variance, higher charge under CMP316 proposed solution
1	North Scotland	100	1	102	98	0	51	49	0	£ 2,574,283	£ 1,687,866	-£ 886,417
2	East Aberdeenshire	100	2	102	98	0	51	49	0	£ 2,236,196	£ 1,422,731	-£ 813,465
3	Western Highlands	100	3	102	98	0	51	49	0	£ 2,441,244	£ 1,594,413	-£ 846,832
4	Skye and Lochalsh	100	4	102	98	0	51	49	0	£ 2,618,730	£ 1,475,785	-£ 1,142,944
5	Eastern Grampian and Tayside	100	5	102	98	0	51	49	0	£ 1,985,579	£ 1,364,102	-£ 621,477
6	Central Grampian	100	6	102	98	0	51	49	0	£ 2,125,821	£ 1,427,746	-£ 698,074
7	Argyll	100	7	102	98	0	51	49	0	£ 2,919,497	£ 1,784,957	-£ 1,134,540
8	The Trossachs	100	8	102	98	0	51	49	0	£ 1,830,456	£ 1,231,862	-£ 598,594
9	Stirlingshire and Fife	100	9	102	98	0	51	49	0	£ 1,656,025	£ 1,076,615	-£ 579,410
10	South West Scotlands	100	10	102	98	0	51	49	0	£ 1,695,759	£ 1,113,894	-£ 581,865
11	Lothian and Borders	100	11	102	98	0	51	49	0	£ 1,031,815	£ 741,832	-£ 289,983
12	Solway and Cheviot	100	12	102	98	0	51	49	0	£ 977,546	£ 680,861	-£ 296,685
13	North East England	100	13	102	98	0	51	49	0	£ 626,647	£ 520,024	-£ 106,624
14	North Lancashire and The Lakes	100	14	102	98	0	51	49	0	£ 311,109	£ 301,800	-£ 9,309
15	South Lancashire, Yorkshire and Humber	100	15	102	98	0	51	49	0	£ 94,995	£ 234,518	£ 139,523
16	North Midlands and North Wales	100	16	102	98	0	51	49	0	£ 4,929	£ 149,018	£ 144,089
17	South Lincolnshire and North Norfolk	100	17	102	98	0	51	49	0	£ 29,676	£ 73,960	£ 44,284
18	Mid Wales and The Midlands	100	18	102	98	0	51	49	0	£ 38,253	£ 94,847	£ 56,594
19	Anglesey and Snowdon	100	19	102	98	0	51	49	0	£ 10,079	£ 231,818	£ 221,739
20	Pembrokeshire	100	20	102	98	0	51	49	0	-£ 253,574	£ 192,018	£ 445,591
21	South Wales & Gloucester	100	21	102	98	0	51	49	0	-£ 265,669	-£ 13,057	£ 252,612
22	Cotswold	100	22	102	98	0	51	49	0	-£ 744,992	-£ 305,051	£ 439,941
23	Central London	100	23	102	98	0	51	49	0	-£ 450,616	-£ 432,631	£ 17,985
24	Essex and Kent	100	24	102	98	0	51	49	0	£ 100,566	-£ 107,988	-£ 208,555
25	Oxfordshire, Surrey and Sussex	100	25	102	98	0	51	49	0	-£ 93,924	-£ 118,056	-£ 24,131
26	Somerset and Wessex	100	26	102	98	0	51	49	0	-£ 145,655	-£ 213,125	-£ 67,470
27	West Devon and Cornwall	100	27	102	98	0	51	49	0	-£ 326,063	-£ 342,760	-£ 16,697



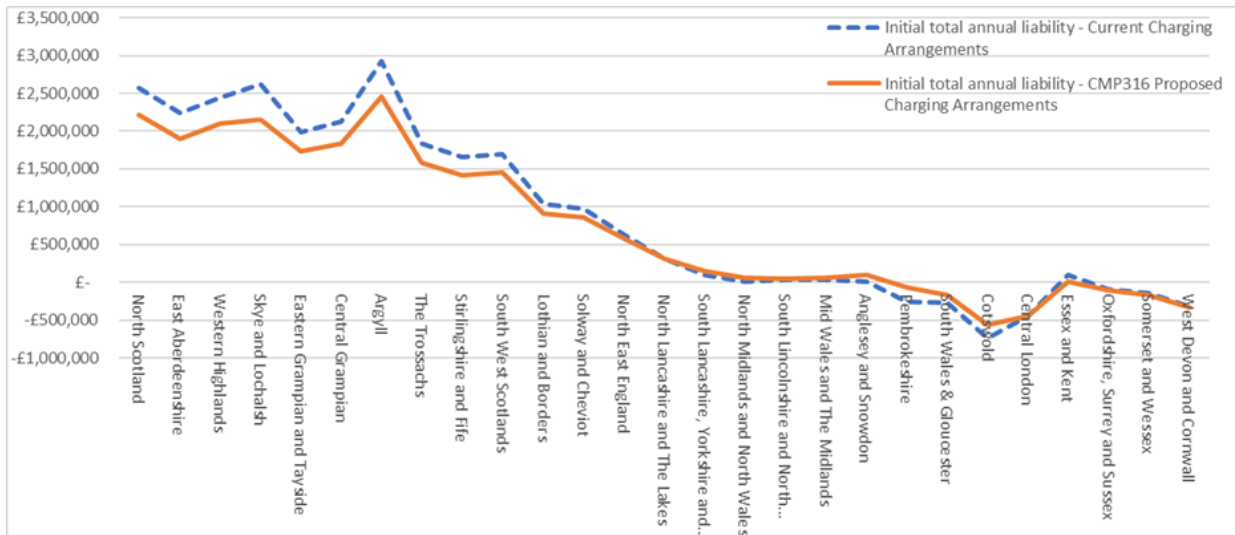
**Example 5:** Similarly provides an example discussed by the Workgroup that was considered to be the most popular technology combinations consisting of onshore wind and battery. This example was considered by the Workgroup to be more representative of installed capacity combinations where wind made up the higher proportion of TEC. (Compare to example 4)

MW	STATION A	STATION A1	STATION A2	STATION A3	STATION A
Installed Capacity		100.00	25.00		125.00
TEC	100.00				100.00
MFSSTEC		80.00	20.00	0.00	100.00
Fuel Type	Onshore_Wind	Onshore_Wind	Battery		0.00
Generation Zone	1	1	1	1	
Classification	Intermittent	Intermittent	Conv. Carbon		
Generic ALF	36.0719%	36.0719%	9.7926%		
Specific ALF					
Applied ALF	36.0719%	36.0719%	9.7926%		

MW	STATION A	Technology A1	Technology A2	Technology A3	STATION A
Installed Capacity		100.00	25.00		125.00
TEC	100.00				100.00
MTPSTEC		80.00	20.00	0.00	100.00
Fuel Type	Onshore_Wind	Onshore_Wind	Battery		0.00
Generation Zone	1	1	1		
Classification	Intermittent	Intermittent	Conv. Carbon		
Generic ALF	36.0719%	36.0719%	9.7926%		
Specific ALF					
Applied ALF	36.0719%	36.0719%	9.7926%		



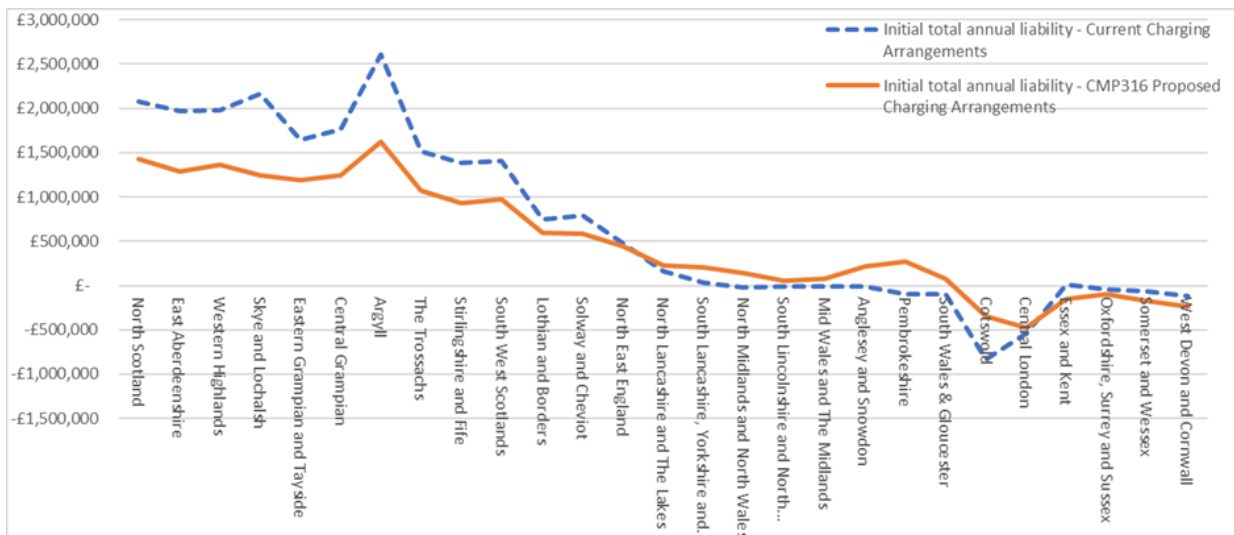
Zone No.	Zone Name	TEC	Generation Zone	Installed Capacity <sub>1</sub>	Installed Capacity <sub>2</sub>	Installed Capacity <sub>3</sub>	MFSSTEC <sub>1</sub>	MFSSTEC <sub>2</sub>	MFSSTEC <sub>3</sub>	Initial total annual liability - Current Charging Arrangements	Initial total annual liability - CMP316 Proposed Charging Arrangements	variance, higher charge under CMP316 proposed solution
1	North Scotland	100	1	100	25	0	80	20	0	£ 2,574,283	£ 2,212,480	-£ 361,803
2	East Aberdeenshire	100	2	100	25	0	80	20	0	£ 2,236,196	£ 1,904,170	-£ 332,026
3	Western Highlands	100	3	100	25	0	80	20	0	£ 2,441,244	£ 2,095,599	-£ 345,646
4	Skye and Lochalsh	100	4	100	25	0	80	20	0	£ 2,618,730	£ 2,152,222	-£ 466,508
5	Eastern Grampian and Tayside	100	5	100	25	0	80	20	0	£ 1,985,579	£ 1,731,915	-£ 253,664
6	Central Grampian	100	6	100	25	0	80	20	0	£ 2,125,821	£ 1,840,892	-£ 284,928
7	Argyll	100	7	100	25	0	80	20	0	£ 2,919,497	£ 2,456,420	-£ 463,078
8	The Trossachs	100	8	100	25	0	80	20	0	£ 1,830,456	£ 1,586,132	-£ 244,324
9	Stirlingshire and Fife	100	9	100	25	0	80	20	0	£ 1,656,025	£ 1,419,531	-£ 236,494
10	South West Scotland	100	10	100	25	0	80	20	0	£ 1,695,759	£ 1,458,263	-£ 237,496
11	Lothian and Borders	100	11	100	25	0	80	20	0	£ 1,031,815	£ 913,454	-£ 118,360
12	Solway and Cheviot	100	12	100	25	0	80	20	0	£ 977,546	£ 856,450	-£ 121,096
13	North East England	100	13	100	25	0	80	20	0	£ 626,647	£ 583,128	-£ 43,520
14	North Lancashire and The Lakes	100	14	100	25	0	80	20	0	£ 311,109	£ 307,309	-£ 3,800
15	South Lancashire, Yorkshire and Humber	100	15	100	25	0	80	20	0	£ 94,995	£ 151,943	£ 56,948
16	North Midlands and North Wales	100	16	100	25	0	80	20	0	£ 4,929	£ 63,740	£ 58,812
17	South Lincolnshire and North Norfolk	100	17	100	25	0	80	20	0	£ 29,676	£ 47,751	£ 18,075
18	Mid Wales and The Midlands	100	18	100	25	0	80	20	0	£ 38,253	£ 61,353	£ 23,099
19	Anglesey and Snowdon	100	19	100	25	0	80	20	0	£ 10,079	£ 100,585	£ 90,506
20	Pembrokeshire	100	20	100	25	0	80	20	0	£ 253,574	£ 71,700	£ 181,874
21	South Wales & Gloucester	100	21	100	25	0	80	20	0	£ 265,669	£ 162,562	£ 103,107
22	Cotswold	100	22	100	25	0	80	20	0	£ 744,992	£ 565,424	£ 179,568
23	Central London	100	23	100	25	0	80	20	0	£ 450,616	£ 443,275	£ 7,341
24	Essex and Kent	100	24	100	25	0	80	20	0	£ 100,566	£ 15,442	£ 85,124
25	Oxfordshire, Surrey and Sussex	100	25	100	25	0	80	20	0	£ 93,924	£ 103,774	£ 9,850
26	Somerset and Wessex	100	26	100	25	0	80	20	0	£ 145,655	£ 173,194	£ 27,539
27	West Devon and Cornwall	100	27	100	25	0	80	20	0	£ 326,063	£ 332,878	£ 6,815



**Example 6:** This example is a variation of the technology types to cover solar/battery combinations. These are the same generation charging category as wind/battery but the ALFs for solar are likely to be lower than the ALFs for wind. Installed capacities are assumed to be near equal. (Compare to example 4)

MW	STATION A	Technology A1	Technology A2	Technology A3	STATION A
Installed Capacity		102.00	98.00		200.00
TEC	100.00				100.00
MTPSTEC		51.00	49.00	0.00	100.00
Fuel Type	Solar	Solar	Battery		0.00
Generation Zone	1	1	1		
Classification	Intermittent	Intermittent	Conv. Carbon		
Generic ALF	10.8000%	10.8000%	9.7926%		
Specific ALF					
Applied ALF	10.8000%	10.8000%	9.7926%		

Zone No.	Zone Name	TEC	Generation Zone	Installed Capacity <sub>1</sub>	Installed Capacity <sub>2</sub>	Installed Capacity <sub>3</sub>	MFSSTEC <sub>1</sub>	MFSSTEC <sub>2</sub>	MFSSTEC <sub>3</sub>	Initial total annual liability - Current Charging Arrangements	Initial total annual liability - CMP316 Proposed Charging Arrangements	variance, higher charge under CMP316 proposed solution
1	North Scotland	100	1	102	98	0	51	49	0	2,072,657	1,432,037	-640,620
2	East Aberdeenshire	100	2	102	98	0	51	49	0	1,971,434	1,287,702	-683,731
3	Western Highlands	100	3	102	98	0	51	49	0	1,983,195	1,360,807	-622,388
4	Skye and Lochalsh	100	4	102	98	0	51	49	0	2,160,680	1,242,180	-918,500
5	Eastern Grampian and Tayside	100	5	102	98	0	51	49	0	1,647,630	1,191,748	-455,882
6	Central Grampian	100	6	102	98	0	51	49	0	1,764,380	1,243,412	-520,968
7	Argyll	100	7	102	98	0	51	49	0	2,606,839	1,625,501	-981,338
8	The Trossachs	100	8	102	98	0	51	49	0	1,517,798	1,072,406	-445,392
9	Stirlingshire and Fife	100	9	102	98	0	51	49	0	1,379,749	935,714	-444,035
10	South West Scotland	100	10	102	98	0	51	49	0	1,410,614	968,470	-442,144
11	Lothian and Borders	100	11	102	98	0	51	49	0	746,670	596,408	-150,262
12	Solway and Cheviot	100	12	102	98	0	51	49	0	785,346	582,839	-202,507
13	North East England	100	13	102	98	0	51	49	0	477,874	444,149	-33,725
14	North Lancashire and The Lakes	100	14	102	98	0	51	49	0	162,335	225,925	63,590
15	South Lancashire, Yorkshire and Humber	100	15	102	98	0	51	49	0	34,425	203,627	169,202
16	North Midlands and North Wales	100	16	102	98	0	51	49	0	16,922	137,874	154,796
17	South Lincolnshire and North Norfolk	100	17	102	98	0	51	49	0	9,513	53,974	63,486
18	Mid Wales and The Midlands	100	18	102	98	0	51	49	0	6,945	71,796	78,741
19	Anglesey and Snowdon	100	19	102	98	0	51	49	0	15,380	218,834	234,214
20	Pembrokeshire	100	20	102	98	0	51	49	0	94,318	273,238	367,556
21	South Wales & Gloucester	100	21	102	98	0	51	49	0	97,939	72,485	-170,424
22	Cotswold	100	22	102	98	0	51	49	0	833,846	350,367	-483,479
23	Central London	100	23	102	98	0	51	49	0	539,471	477,947	-61,524
24	Essex and Kent	100	24	102	98	0	51	49	0	11,712	153,304	165,016
25	Oxfordshire, Surrey and Sussex	100	25	102	98	0	51	49	0	46,519	93,879	47,360
26	Somerset and Wessex	100	26	102	98	0	51	49	0	62,007	170,465	108,457
27	West Devon and Cornwall	100	27	102	98	0	51	49	0	116,022	235,639	119,617



**Example 7:** This example explores any unintended consequences of the modification. The Workgroup discussed what would happen to a station's costs if a battery were to be added to an existing conventional carbon technology type. It was discussed that costs should be unchanged if the metered output of the station is unchanged. Specific ALFs at

the child station level are calculated consistent with the example where there is no change to metered output of the station.

The parent/child ALFs in this example are calculated as follows:

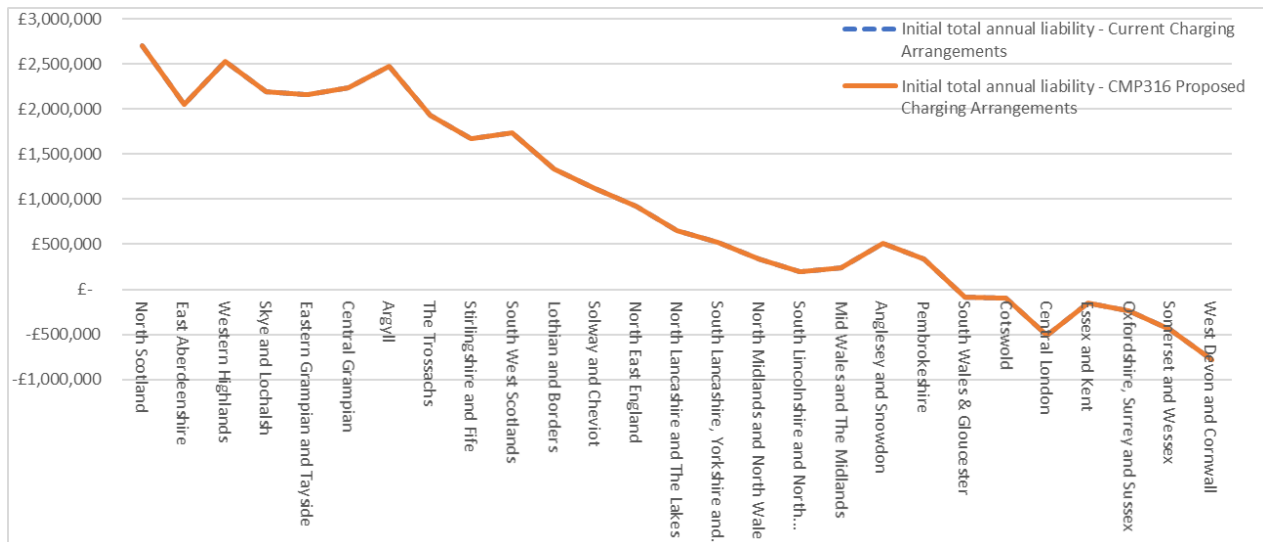
- The station has 100MW TEC and would have 876GWh output if the station operated at maximum capacity across the whole year. Output in the example is 525.6GWh which calculates to 60% ALF (525.6/876)
- For the child stations, the MTPSTEC for CCGT and the battery are 71MW and 29MW respectively. For this example, a n assumption has been made that the output remains mainly from CCGT with 525GWh output which is 84% MTSALF (525/625.7) with nominal output of 0.6GWh (0.2% ALF) which means that total output for the station is unchanged. This results in no change to the station costs for any generation zone, in total, with the CMP316 proposed solution.



MW	STATION A	STATION A1	STATION A2	STATION A3	STATION A
Installed Capacity		100.00	40.00		140.00
TEC	100.00				100.00
MFSSTEC		71.43	28.57	0.00	100.00
Fuel Type	CCGT_CHP	CCGT_CHP	Battery		0.00
Generation Zone	1	1	1	1	
Classification	Conv. Carbon	Conv. Carbon	Conv. Carbon		
Generic ALF	51.0635%	51.0635%	9.7926%		
Specific ALF	60.0000%	83.9036%	0.2397%		
Applied ALF	60.0000%	83.9036%	0.2397%		
Max output (MWh)	876,000	625,718	250,282	-	
Actual output (MWh)	525,600	525,000	600	-	

MW	STATION A	Technology A1	Technology A2	Technology A3	STATION A
Installed Capacity		100.00	40.00		140.00
TEC	100.00				100.00
MTPSTEC		71.43	28.57	0.00	100.00
Fuel Type	CCGT_CHP	CCGT_CHP	Battery		0.00
Generation Zone	1	1	1		
Classification	Conv. Carbon	Conv. Carbon	Conv. Carbon		
Generic ALF	51.0635%	51.0635%	9.7926%		
Specific ALF	60.0000%	83.9036%	0.2397%		
Applied ALF	60.0000%	83.9036%	0.2397%		
Max output (MWh)	876,000	625,718	250,282	-	
Actual output (MWh)	525,600	525,000	600		

Zone No.	Zone Name	TEC	Generation Zone	Installed Capacity <sub>1</sub>	Installed Capacity <sub>2</sub>	Installed Capacity <sub>3</sub>	MFSSTEC <sub>1</sub>	MFSSTEC <sub>2</sub>	MFSSTEC <sub>3</sub>	Initial total annual liability - Current Charging Arrangements	Initial total annual liability - Proposed Charging Arrangements	variance, higher charge under CMP316 proposed solution
1	North Scotland	100	1	100	40	0	71	29	0	£ 2,714,358	£ 2,714,358	£ -
2	East Aberdeenshire	100	2	100	40	0	71	29	0	£ 2,054,581	£ 2,054,581	£ -
3	Western Highlands	100	3	100	40	0	71	29	0	£ 2,539,967	£ 2,539,967	£ -
4	Skye and Lochalsh	100	4	100	40	0	71	29	0	£ 2,202,251	£ 2,202,251	£ -
5	Eastern Grampian and Tayside	100	5	100	40	0	71	29	0	£ 2,162,898	£ 2,162,898	£ -
6	Central Grampian	100	6	100	40	0	71	29	0	£ 2,247,065	£ 2,247,065	£ -
7	Argyll	100	7	100	40	0	71	29	0	£ 2,486,523	£ 2,486,523	£ -
8	The Trossachs	100	8	100	40	0	71	29	0	£ 1,944,470	£ 1,944,470	£ -
9	Stirlingshire and Fife	100	9	100	40	0	71	29	0	£ 1,675,405	£ 1,675,405	£ -
10	South West Scotland	100	10	100	40	0	71	29	0	£ 1,741,343	£ 1,741,343	£ -
11	Lothian and Borders	100	11	100	40	0	71	29	0	£ 1,339,728	£ 1,339,728	£ -
12	Solway and Cheviot	100	12	100	40	0	71	29	0	£ 1,126,489	£ 1,126,489	£ -
13	North East England	100	13	100	40	0	71	29	0	£ 932,140	£ 932,140	£ -
14	North Lancashire and The Lakes	100	14	100	40	0	71	29	0	£ 656,779	£ 656,779	£ -
15	South Lancashire, Yorkshire and Humber	100	15	100	40	0	71	29	0	£ 523,876	£ 523,876	£ -
16	North Midlands and North Wales	100	16	100	40	0	71	29	0	£ 348,732	£ 348,732	£ -
17	South Lincolnshire and North Norfolk	100	17	100	40	0	71	29	0	£ 204,240	£ 204,240	£ -
18	Mid Wales and The Midlands	100	18	100	40	0	71	29	0	£ 249,878	£ 249,878	£ -
19	Anglesey and Snowdon	100	19	100	40	0	71	29	0	£ 519,521	£ 519,521	£ -
20	Pembrokeshire	100	20	100	40	0	71	29	0	£ 345,739	£ 345,739	£ -
21	South Wales & Gloucester	100	21	100	40	0	71	29	0	£ 77,026	£ 77,026	£ -
22	Cotswold	100	22	100	40	0	71	29	0	£ 88,827	£ 88,827	£ -
23	Central London	100	23	100	40	0	71	29	0	£ 507,787	£ 507,787	£ -
24	Essex and Kent	100	24	100	40	0	71	29	0	£ 142,196	£ 142,196	£ -
25	Oxfordshire, Surrey and Sussex	100	25	100	40	0	71	29	0	£ 231,018	£ 231,018	£ -
26	Somerset and Wessex	100	26	100	40	0	71	29	0	£ 443,198	£ 443,198	£ -
27	West Devon and Cornwall	100	27	100	40	0	71	29	0	£ 771,092	£ 771,092	£ -

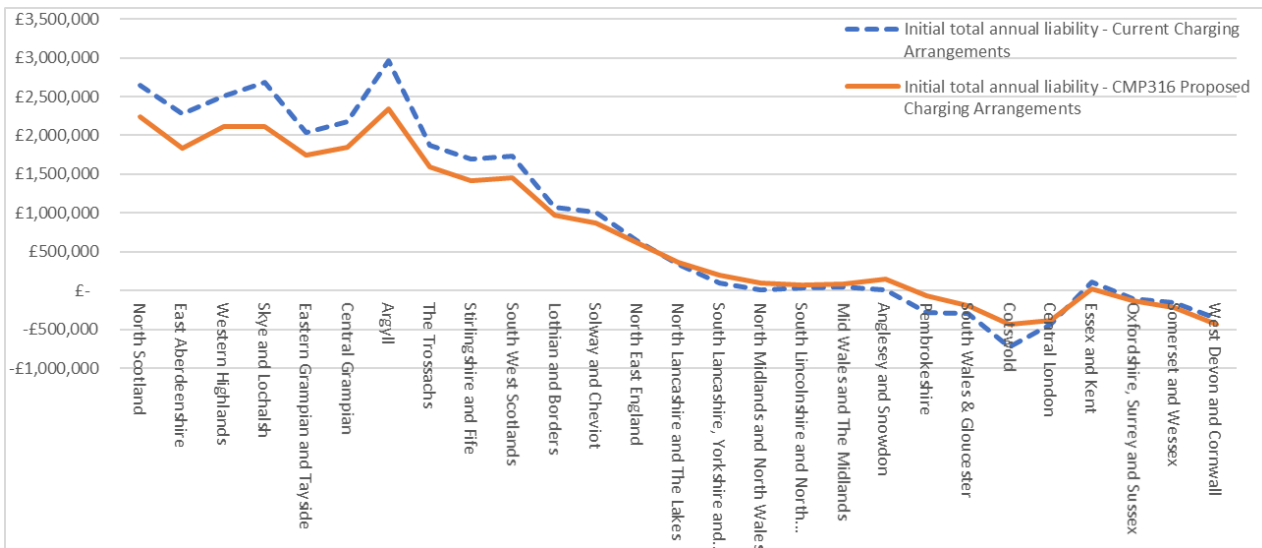


**Example 8:** This example is a variation of Example 7 which adds a battery to an existing conventional carbon technology type. Example 8 adds a battery to an existing wind technology type (intermittent generation charging category) Similarly, total station output is assumed to be the same with nominal output from the new battery. In this example total charges for the station are different, depending upon the generation zone. The Workgroup’s view in this example was that the costs to purchase, commission and connect the additional battery would be sufficiently prohibitive to help deter potential gaming of this charging solution. It was also noted in the Workgroup that purchase of the battery does provide additional flexibility to the system.

MW	STATION A	STATION A1	STATION A2	STATION A3	STATION A
Installed Capacity		100.00	40.00		140.00
TEC	100.00				100.00
MFSSTEC		71.43	28.57	0.00	100.00
Fuel Type	Onshore_Wind	Onshore_Wind	Battery		0.00
Generation Zone	1	1	1	1	
Classification	Intermittent	Intermittent	Conv. Carbon		
Generic ALF	36.0719%	36.0719%	9.7926%		
Specific ALF	39.9543%	55.1367%	1.9977%		
Applied ALF	39.9543%	55.1367%	1.9977%		
Max output (MWh)	876,000	625,718	250,282	-	
Actual output (MWh)	350,000	345,000	5,000	-	

MW	STATION A	Technology A1	Technology A2	Technology A3	STATION A
Installed Capacity		100.00	40.00		140.00
TEC	100.00				100.00
MTPSTEC		71.43	28.57	0.00	100.00
Fuel Type	Onshore_Wind	Onshore_Wind	Battery		0.00
Generation Zone	1	1	1		
Classification	Intermittent	Intermittent	Conv. Carbon		
Generic ALF	36.0719%	36.0719%	9.7926%		
Specific ALF	39.9543%	55.1367%	1.9977%		
Applied ALF	39.9543%	55.1367%	1.9977%		
Max output (MWh)	876,000	625,718	250,282	-	
Actual output (MWh)	350,000	345,000	5,000		

Zone No.	Zone Name	TEC	Generation Zone	Installed Capacity <sub>1</sub>	Installed Capacity <sub>2</sub>	Installed Capacity <sub>3</sub>	MFSSTEC <sub>1</sub>	MFSSTEC <sub>2</sub>	MFSSTEC <sub>3</sub>	Initial total annual liability - Current Charging Arrangements	Initial total annual liability - CMP316 Proposed Charging Arrangements	variance, higher charge under CMP316 proposed solution
1	North Scotland	100	1	100	40	0	71	29	0	£ 2,651,346	£ 2,241,555	-£ 409,791
2	East Aberdeenshire	100	2	100	40	0	71	29	0	£ 2,276,871	£ 1,839,245	-£ 437,626
3	Western Highlands	100	3	100	40	0	71	29	0	£ 2,511,613	£ 2,113,535	-£ 398,079
4	Skye and Lochalsh	100	4	100	40	0	71	29	0	£ 2,689,098	£ 2,114,409	-£ 574,689
5	Eastern Grampian and Tayside	100	5	100	40	0	71	29	0	£ 2,037,497	£ 1,741,468	-£ 296,030
6	Central Grampian	100	6	100	40	0	71	29	0	£ 2,181,348	£ 1,845,258	-£ 336,089
7	Argyll	100	7	100	40	0	71	29	0	£ 2,967,530	£ 2,343,225	-£ 624,304
8	The Trossachs	100	8	100	40	0	71	29	0	£ 1,878,489	£ 1,590,938	-£ 287,551
9	Stirlingshire and Fife	100	9	100	40	0	71	29	0	£ 1,698,468	£ 1,414,023	-£ 284,446
10	South West Scotlands	100	10	100	40	0	71	29	0	£ 1,739,565	£ 1,455,720	-£ 283,845
11	Lothian and Borders	100	11	100	40	0	71	29	0	£ 1,075,620	£ 976,753	-£ 98,867
12	Solway and Cheviot	100	12	100	40	0	71	29	0	£ 1,007,073	£ 874,938	-£ 132,135
13	North East England	100	13	100	40	0	71	29	0	£ 649,503	£ 621,722	-£ 27,781
14	North Lancashire and The Lakes	100	14	100	40	0	71	29	0	£ 333,964	£ 369,953	£ 35,988
15	South Lancashire, Yorkshire and Humber	100	15	100	40	0	71	29	0	£ 104,301	£ 202,874	£ 98,574
16	North Midlands and North Wales	100	16	100	40	0	71	29	0	£ 8,285	£ 98,793	£ 90,507
17	South Lincolnshire and North Norfolk	100	17	100	40	0	71	29	0	£ 35,696	£ 73,160	£ 37,464
18	Mid Wales and The Midlands	100	18	100	40	0	71	29	0	£ 45,197	£ 91,624	£ 46,427
19	Anglesey and Snowdon	100	19	100	40	0	71	29	0	£ 13,991	£ 150,846	£ 136,856
20	Pembrokeshire	100	20	100	40	0	71	29	0	£ 278,039	£ 65,538	£ 212,501
21	South Wales & Gloucester	100	21	100	40	0	71	29	0	£ 291,436	£ 193,975	£ 97,461
22	Cotswold	100	22	100	40	0	71	29	0	£ 731,342	£ 429,590	£ 301,751
23	Central London	100	23	100	40	0	71	29	0	£ 436,966	£ 387,805	£ 49,160
24	Essex and Kent	100	24	100	40	0	71	29	0	£ 114,217	£ 19,011	£ 95,206
25	Oxfordshire, Surrey and Sussex	100	25	100	40	0	71	29	0	£ 101,207	£ 129,362	£ 28,155
26	Somerset and Wessex	100	26	100	40	0	71	29	0	£ 158,506	£ 222,698	£ 64,192
27	West Devon and Cornwall	100	27	100	40	0	71	29	0	£ 358,331	£ 430,470	£ 72,139



The Workgroup felt that these worked examples were required so that it is transparent to industry about how different site scenarios are being proposed to be charged if the CMP316 Original solution were to be approved. The examples cover the instances below and show inputs/outputs which can be replicated within the CMP316 Tool spreadsheet.

#### - Three technology types on a co-located site

Illustrated by an example within the spreadsheet which has coal, biomass, and battery storage.

#### - A site has used at least two months of non-permanent TEC (such as the within year Temporary TEC Transfer or LDTEC or STTEC products)

In this example there is one station at the contract 'parent' level with TEC. Charging will be calculated at the technology type level. The non-permanent TEC will also be applied at the technology type level.

#### - Hypothetical examples of sites in positive and negative generation charging zones

Illustrated by an example within the spreadsheet.

#### - Extreme cases of large and small load factors

Illustrated by an example within the spreadsheet.

#### - What happens in the event of permanent TEC transfer

The Proposer does not expect fuel mix to differ for a permanent TEC transfer. The design for network capacity would already have taken capacity into account when designing the system.

#### - How the modification works when TEC is altered

The principle remains unchanged from today which applies the highest TEC within the charging year; i.e. if TEC decreases then the higher amount is charged until the new charging year.

#### - Unused connection assets

Connection asset charges are not based on usage but upon the value of the asset. There is no change in this CMP316 solution proposed to the TNUoS charging methodology applied today.

### **- What happens if a site adds/changes technology within the same category**

Since each technology type for co-located generation sites will have its own BMU/metering then the ALF will be applied separately to each as if they are standalone stations. Therefore, despite being within the same Wider Generation Charging Category each technology type will have a different tariff due to use of individual ALFs associated with MTSTEC.

### **- If a site goes from being co-located to single technology**

In this instance, the ESO would apply the TNUoS charging methodology as it is today and would relate it to one technology type only rather than two. It is likely that the site will reflect the co-located solution for the current charging year. From the next charging year, the tariff will then reflect the single technology. The Proposer's preference is that the two tariffs should be pro-rated across the charging year.

### **- Two technologies behind one meter (e.g., storage and intermittent)**

If each technology type for co-located generation sites does not have its own BMU/metering, then the existing TNUoS charging methodology will prevail: i.e. the site

charge will continue to be based upon the predominant technology type as per the current charging arrangements. The Workgroup also discussed how any potential gaming opportunity could be mitigated (see paragraph below).

In the Grid Code there are two forms of metering; (i) Settlement Metering (used for payment purposes, see Grid Code CC/ECC.6.2.2.3.5) and (ii) Operational Metering (used for metering purely for operating the system, see Grid Code CC/ECC.6.4.4 and CC/ECC.6.5.6). In terms of Co-located sites, this is a choice for the developer in terms of how they wish to configure their system and where the ownership boundary is between the User's Plant and System. It also depends if the developer wishes to run their plant as one or individually which will in turn affect the metering. For storage applicants it is quite common to have a co-located site with generation and storage combined, so that the storage can cover the short-term deficit in power output when there is a frequency change. It is however down to the developer to register how they want to configure their plant.

### **Sourcing installed capacity by technology type from Contracts (Original Proposal)**

The Original solution currently proposes to source the TEC from the connection contracts that the ESO has with each User and to use this in the proposed pro-rata calculation. The Proposer advised that this gives signals to the system of any changes.

Concerns were raised in the Workgroup that the proposed solution requires each technology type to have a separate BMU. It was discussed that currently there is a 1:1 relationship between BMU and fuel type, however it was also raised that there is nothing enforcing this. It was suggested that if more than one technology sits behind an inverter; and therefore only has one BMU; it may need to be the predominant technology type that the charge is based on. A gaming risk was considered as this could lead to some sites putting their different technology types behind one BMU so they would be charged on their predominant technology type. However, it was considered that where there are multiple technologies behind one meter (BMU) the ALF will likely be higher and therefore the TNUoS higher to reflect the increased utilisation of the connection.

A suggestion was made that the more expensive technology type could be used to avoid this risk. However, this was concerning to Workgroup members as this does not achieve cost reflectivity. However, reverting to the tariff for the predominant technology type equally is not cost reflective.

It was suggested by a Workgroup member that the risk of this may be small, as there is an incentive on parties to have separate metering by technology type, otherwise it would limit their ability to trade. For a Multi Technology Power Station where appropriate metering arrangements are in place, an ALF will be calculated for each fuel/technology type. Note that the sum of GMWh for a Multi Technology Power Station across all technology types will equal the total GMWh for the Power Station.

The Proposer explained that their pro-rata methodology is mandatory for all sites which have BMUs by technology type or separate metering by technology type.

The Proposer's view was that separate metering for each technology type ensures such sites can be recognised and charged consistently with the cost-reflective principles underpinning the broader Generator TNUoS charging methodology.

Legal text will be finalised and ALF at each technology type will be represented by a new term within the CUSC formula. For a Multi Fuel Power Station (as 14.15.8) where appropriate metering arrangements are in place, an ALF will be calculated for each technology type. Note that the sum of GMWh for a Multi Fuel Power Station across all technology types will equal the total GMWh for the Power Station.

$$ALF_A = \frac{\sum_{p=1}^{17520} GMWh_{Ap}}{\sum_{p=1}^{17520} TEC_p \times 0.5^{...}}$$

Where:

A...Z denote each BMU within a Power Station

GMWh<sub>Ap</sub> is the maximum of FPN or actual metered output in a Settlement Period related to the BMUs associated with MTPSTECA

For the alternate only, the following formula applies:

$$ALF_A = \frac{\sum_{p=1}^{17520} GMWh_{Ap}}{8760 \times MTPSTEC_A}$$

It was noted that consideration should be given to the net impact of generation technologies at a site.

For both generation and final demand, charges will still be based on TEC and export capacity. This will be subject to the future TDR methodology if final demand is also required to be reflected.

The sum of the installed capacity for technology types may exceed the TEC. Installed capacity for each technology type is used as a starting point in the proposed CMP316 Original modification solution formula. MTPSTEC uses the installed capacity to determine ratios for every technology type to ensure that the sum of MTPSTEC sums exactly to TEC. Each child station will be charged individually and then summed so that the site continues to be charged total TEC. (See formula in Proposer's Solution e.g. Total station TEC=60MW with installed capacity for 2 technology types as 50MW and 30MW respectively. MTPSTEC would be calculated, using installed capacity proportions, as 37.5MW and 22.5MW which sums exactly to the station TEC of 60MW).

The required process to address the above will be covered in the implementation stage and management of the process going forward. Presently, there are only a small number of sites that would be required to update their contracts and the Workgroup and Proposer considered that it would not be fair for these sites to pay to update what they currently have. If they are changing what they have on site, then a Mod App will apply as per today.

The Proposer stated that transition arrangements will be reviewed to ensure that existing and future co-located sites with different technology types installed (capacity and ALFs) are made available to support implementation of the new solution. The Workgroup raised concerns that if a Mod App is required for this then this would create unnecessary expense for industry participants. The Proposer clarified that it was not the intention from the ESO to create additional and expensive Mod Apps to support this implementation of CMP316 Original. It was confirmed by the Proposer that if the CMP316 Original modification was implemented, there would be no Mod App expenses required for co-located parties with existing contracts. Reasons for continuing to raise Mod Apps are unchanged from today.

### **Sourcing installed capacity via a declarations process (Potential Alternative)**

Workgroup members advocated that the TNUoS charge needs to reflect the usage of the transmission system. Concerns were raised that the potential solution, which uses TEC capacity set out in contracts may not achieve this as TEC in those contracts can be in certain circumstances (e.g., in positive TNUoS zones) more than TEC actually used.

An option was considered which would look at capacity used rather than the capacity set out in the contracts between the ESO and the Users. It was suggested that the declaration process which has been developed as part of the recent Transmission Demand Residual modifications could be adopted for this.

The Workgroup reviewed the precedent set by intended declaration process for TDR where there are a number of CUSC modifications which require the creation of a 'declaration process' to remove certain types of sites from BSUoS charges and/or TNUoS residual charges. The Workgroup reviewed this intended process to see how this could map across to the CMP316 proposed solution. The Proposer's view was that the TDR declaration process manages a binary outcome (i.e., is the site exempt from BSUoS/TNUoS charges or not) and therefore differs from provision of forecast usage by technology type which has a range of outcomes. Since usage would also be a forecast, by definition, in the Proposer's view this will be incorrect and adds complexity if the ESO are required to govern the accuracy of this forecast and thresholds of inaccurate declarations would need to be considered for validity checks.

One Workgroup member did not see the TDR process as a binary concept and explained that there are a number of situations where there are unique site circumstances.

The Proposer added that for the TDR declaration process, there was no existing process/data item suitable for use. It was considered by the Proposer that it would be better to use data that is available rather than creating a new process to achieve this.

If a declaration method was to be used, Workgroup members advised that this would need to be mandatory rather than optional; as it may be in the interests of some sites that their predominant TEC is used, which could lead to some sites deciding not to make declarations.

It was questioned what would happen if not all users had declared their proportions of technology before the set deadline to determine the tariffs. It was queried whether this



would require a mid-year tariff reset. It was also suggested that some could miss the deadline if it was in their favour to, so there would need to be stringent rules/fines in place. It was also noted that there may be a risk that the generator cap (which keeps total TNUoS recovery from generators within the range of €0-2.50/MWh) could be exceeded if some sites missed the deadline, and there had to be an adjustment following this that exceeded the cap.

It was emphasised by Workgroup members that there would need to be appropriate checks in place for any solution which relies on user-declared capacity. The TDR declarations process involves the company Director having to submit a formal declaration. It was suggested that the declaration would need to follow a specific format and that it should include the megawatts installed, rather than just the ratio of technology types installed at a site.

It was suggested that a re-declaration process would be a beneficial exercise, and that this could be done in line with the ESO's price control review.

It was suggested that a user-declared method may be easier to manage, particularly if small distributed generators were to be included in this in future.

### **Definition of Installed Capacity**

The Workgroup discussed whether "Installed Capacity" should be a defined term. They sought where it may be defined in other Codes. The BSC (Section K3.4.8) includes a definition for "Generation Capacity" (GC) – the Proposer considered and explained to the Workgroup the following reasons why they did not see this as an appropriate definition:

- Does not refer to the same context and deals with generator security under the BSC
- Does not seem comparable to use 'GC' from the BSC as a measure of capacity, as GC is used for financial security and is directly related to actual output/consumption. This means it will have adverse impacts on sites with very low output/consumption values and how this is used to pro-rata TEC across tech types.
- Consideration would need to be given to how this translates to a MWh number and what would be used for the ALF. There is a risk that cause issues with other TNUoS variables.

The Proposer's expectation is that the installed capacity should not change frequently however the process referred to in BSC suggests a process to manage more frequent change.

The Proposer suggested defining "Installed Capacity" within CUSC Section 14.

### **Co-utilisation of TEC**

The Workgroup discussed the impact of this modification on co-utilisation of TEC. The Proposer confirmed that the CMP316 solution does not look at TEC sharing between different sites and believed this to be excluded from the scope of this modification.

The solution considers multiple technologies within a single site / single connection agreement only. The solution does not cater for sharing between sites.

One Workgroup member explained that they believed the proposed solution is less cost reflective of the use of the Transmission System for those sites with different types of technology in different charging categories that “share” TEC i.e. where the TEC is less than the sum of the installed capacities.

Other Workgroup members preferred the use of the term TEC “co-utilisation” to describe TEC that is shared between different technologies on the same site rather than TEC “sharing” which has been used in previous modification proposals to describe an arrangement where TEC could be shared between entities and different sites.

The Workgroup member went on to explain that they believed co-located sites already get the benefit of a “discount” on their TEC compared to standalone sites and that this modification proposal would change the charging category that the “discount” is applied to so that the benefit is pro-rated across the different charging categories.

The change in charges would depend on which zone a site was located in, but the biggest impact would be on wind generation sites in Scotland and Solar PV in the South West that installed a battery. This type of site would typically not need to increase its TEC because a battery is not likely to be generating at the same time as the intermittent generation, and a high degree of TEC co-utilisation would be expected. Hence, charges for these types of sites could fall substantially, and in some cases almost halve, by installing a battery.

The Workgroup member was concerned that the MTSTEC does not reflect the actual expected generation for the corresponding Peak and Year Round backgrounds, and therefore that some sites might be charged in a significantly less cost reflective way than they are at the moment. This effect could make co-location of different types of technologies become commercially viable in some regions where it was not before, and unviable in others, as a result of a change in charging methodology which they believed is not necessarily cost reflective. The Workgroup member suggested that a better solution would consider co-located sites’ use of the Transmission System during the Peak and Year Round backgrounds and charge Peak, Year Round Shared, and not shared tariffs more according to site behaviour. The Proposer agreed that this solution would work but believes that this suggestion is more complex and less transparent compared to the Original Proposal.

### **Charging for Negative Zones**

The Workgroup considered how multi technology sites in negative tariff zones should be charged, resulting in an addition to both the Original and WACM1 methodologies. In both instances, installed capacity and TEC are replaced by the average output of the unit (or generator for TEC) over the three settlement periods of highest output from November to the end of February each year.

## **Workgroup consultation summary**

The Workgroup held their Workgroup Consultation between 7 February 2022 to 28 February 2022 and received eight responses. The full responses and a summary of the responses can be found in Annex 3.

### **Comments on implementation**

- Need clarity on implementation – how it affects existing and future co-located sites.
- Billing and invoicing of MTSTEC needs to be clear.

- More clarity needed re obligations for separate BMU/Metering for each technology and the applicability of the MTSTEC methodology.
- The proposed implementation date of 01/04/2023 is deemed reasonable as this aligns with the upcoming TNUoS charging year, however this will only leave NGENSO 6 months from decision to implementation, which could be challenging.
- Workgroup discussion on responses: The Proposer has changed the implementation date to 1 April 2024. The Proposer stated that the appropriate metering must be in place in order for the solution to apply. It was suggested that this could mean that future sites could choose not to have separate metering if it was a cheaper option. There was an expectation that co-located sites would have separate metering in the main as it would be more commercially beneficial in terms of trading separately. There was also suggestion that the Balancing and

Settlement Code may restrict two technology types from being combined under one meter.

In the Grid Code there are two forms of metering; (i) Settlement Metering (used for payment purposes, see Grid Code CC/ECC.6.2.2.3.5) and (ii) Operational Metering (used for metering purely for operating the system, see Grid Code CC/ECC.6.4.4 and CC/ECC.6.5.6).

The Workgroup noted the challenging timing of the implementation.

### Issues identified

- One respondent believed the current defect to not be as material as the defect the modification would create.
- Not clear that solution addresses the issue. There is an issue with the solution in respect of the peak charge when conventional and intermittent plant share TEC, plus the Not Shared Year-Round charge when low carbon and carbon plant share a TEC (example given in response).
- One respondent believed that this modification would introduce a new defect by giving some sites the opportunity to significantly reduce their TNUoS charges where site TEC can be shared across different co-located technology types. Concerned that the current TNUoS arrangements are not well designed for batteries which are used on most sites as the secondary technology. Concerned that this proposal will result in an increase in battery capacity liable for TNUoS Charges based on the current Conventional Carbon tariff. The mod would introduce complexity. Believes the charging arrangements for batteries and co-located generation sites should be reviewed through a TNUoS Review, the Taskforce and/or the SQSS Review.
- One respondent believed the mod will benefit co-located sites in Scotland (year round tariffs) with wind as the secondary technology.

Workgroup discussion on responses: A WACM was raised following the Workgroup Consultation which addresses some of these concerns.

There is no direct impact to the SQSS identified in this modification, however it is noted that the TNUoS Call for Evidence is looking to review links with the TNUoS methodology and SQSS.

### Publishing MTSTEC on TEC register

- It was generally agreed that publishing the MTSTEC on the TEC register would be beneficial in terms of transparency. However, one respondent stated there would

be confidentiality issues in relation to publishing the MTSTEC for each tech type on the TEC register for co-located assets.

Workgroup discussion on responses: Noted by the Workgroup.

### **Declarations vs Contracts**

- Most respondents believed the declarations route would lead to an increased admin burden and potential for less accurate data than sourcing from contracts.
- Suggested use of the unit CEC for installed capacity in Connection Agreement. Concern if there is not a suitable figure within the Connection Agreement to use.
- One believed that Registered Capacity is already available to the ESO to source 'installed capacity'.
- One respondent supported the declaration (and redeclaration) route to capture varying situations at a site which may be different to what was set out in the Connection Agreement originally.

Workgroup discussion on responses: The Workgroup member in favour of the declaration route did not pursue the declarations route as an alternative request.

Registered Capacity (RC) is not defined in Connection Agreements therefore this term cannot be used to source 'installed capacity' for the pro-rata equation. RC is determined by the User and declared as part of the Week 24 submissions. Changes made by the User are reflected in Grid Code compliance testing but not included in the connection agreement. Connection Agreements refer to CEC and TEC in appendix C to each agreement. The Workgroup discussed using CEC or to add a new term for installed capacity in AppC. Maximum Capacity (MC) as defined within the Grid Code has been agreed to be added to AppC within the Connection Agreement for co-located sites going forward.

### **Workgroup Alternative CUSC Modification (WACM1)**

Following the Workgroup Consultation, WACM1 was raised. It is different to the Original proposal in that:

- The Peak liability is pro-rated using Peak Installed TEC
- The Not Shared Year Round is pro-rated using the ALF to give a scaled Not Shared Year Round liability
- 'Scaled' generic ALFs should be used to scale pro-rated TEC for the Shared Year Round charge

With regards to differences i) and ii), the Original Proposal pro-rates TEC across all elements of the tariff and therefore does not stay true to the intention of the differing wider tariff calculations to reflect (probable) different times of operation.

Differences i) and ii) mean there will be no single capacity (station level or installed) that can be multiplied by 'a wider tariff' to give £ liability. Each sub element of the wider tariff will have a different capacity applied.

Without difference iii), the Original Proposal would understate the level of output where the station TEC is less than total installed capacity, or overstate it in the unlikely situation where the station TEC is higher than total installed capacity.

The full WACM form can be found in Annex 5. Examples of numerical tariff calculations for the WACM can be found in Annex 8.

The Workgroup discussed the WACM.

Some Workgroup members believed this Proposal to be more cost-reflective than the Original.

It was considered that there are six months in which to implement the solution which could be a challenge for this Proposal given the calculation is more complex.

## Legal text

The legal text for this change can be found in Annex 4.

## What is the impact of this change?

Proposer's Assessment against CUSC Charging Objectives	
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;	<b>Positive</b> Facilitates effective competition by having a charging methodology which appropriately reflects charges for the technology types at a site. This is important as the number of multi technology sites is expected to grow rapidly.
(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);	<b>Positive</b> This proposal introduces a more cost reflective way of charging multi technology sites, by having a separate charge component for each technology type.
(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;	<b>Positive</b> This change reflects the growing number of power stations with multiple technologies.
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	<b>N/A</b>
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	<b>Neutral</b>
* The Electricity Regulation referred to in objective (d) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.	

## **Workgroup Vote**

The Workgroup met on 27 July 2022 to carry out their workgroup vote. The full Workgroup vote can be found in Annex 6. The table below provides a summary of the Workgroup members view on the best option to implement this change.

The Applicable CUSC (charging) Objectives are:

- a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;
- b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);
- c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;
- d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency \*; and
- e) To promote efficiency in the implementation and administration of the system charging methodology

\*Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER) The Electricity Regulation referred to in objective (d) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.

The Workgroup concluded by majority that the WACM1 better facilitated the Applicable Objectives than the Baseline.

Option	Number of voters that voted this option as better than the Baseline
Original	1
WACM1	4

## **First Code Administrator Consultation Summary**

The First Code Administrator Consultation was issued on the 4 October 2022 and closed on 1 November 2022 and received 2 responses. A summary of the responses can be found in the table below, and the full responses can be found in Annex 9.

<b>Code Administrator Consultation summary</b>	
<b>Question</b>	
Do you believe that the CMP316 Original Proposal or WACM1 better facilitates the Applicable CUSC Objectives?	<p>Respondent 1 was supportive of both solutions and believed that they better facilitate objectives A and B, as they improve cost reflectivity and remove distortions. They believed the solutions have neutral effects on C, D and E.</p> <p>Respondent 2 did not believe that either of the solutions better facilitate the objectives.</p>
Do you support the proposed implementation approach?	<p>Respondent 1 supported the revised implementation date of 1 April 2024.</p> <p>Respondent 2 put forward that there is currently no concept of co-located sites in the SQSS, and that this should be amended first. They believed the treatment of co-located sites should be part of the current NETS SQSS Review, to allow for a robust assessment of co-located site network requirements and development of an appropriate technical methodology. They believed it would not be cost reflective to charge co-located sites in a different way to how the network is modelled, planned, and expanded.</p>
Do you have any other comments?	<p>Respondent 1 acknowledged the forecasted increase of co-located sites. They stated that guidance will be needed from the ESO to ensure a smooth transition. They commented that the added complexity of WACM1 could be outweighed by providing a more cost reflective charge.</p> <p>Respondent 2 gave no further comments.</p>
<b>Legal text issues raised in the consultation</b>	
None	
<b>EBR issues raised in the consultation</b>	
None	

## **The First Draft Final Modification Report**

The First Draft Final Modification Report was presented to November 2022 CUSC Panel for Panel recommendation vote. Three Panel Members noted that changes to the legal text for CMP316 WACM1 were required as the legal text did not reflect the intent of CMP316 WACM1.

Therefore Panel, under CUSC 8.23.4(iv), asked for the Workgroup to be re-formed to update the legal text for CMP316 WACM1 and at the same time update the worked examples, (Annex 8) as to how CMP316 WACM1 works, to help industry understanding.

The Workgroup met for a further three times between November 2023 and February 2024. Further worked examples were provided to clarify the differences in methodology between WACM1 and the Original Solution, as there had also been some updates to the methodology for sites in negative zones to align mirror treatment of single technology power stations in negative zones (affecting both WACM1 and Original).

The updates for CMP316 WACM1 were discussed at length with Workgroup members who were given the opportunity to question, and input to changes made to the WACM1 legal text and worked examples.

## **Second Code Administrator Consultation Summary**

The Second Code Administrator Consultation was run from 25/03/2024 to 24/04/2024, and specifically focused on the updates to CMP316 WACM1, received 4 non-confidential responses and 0 confidential responses.

<b>Code Administrator Consultation summary</b>	
<b>Question</b>	
<p>Do you believe that the legal text updates to CMP316 WACM1 and updates to Annex 8 now reflect the intent of CMP316 WACM1?</p>	<p>Three out of the four respondents agreed that the legal text updates to CMP316 WACM1 and updates to Annex 8 reflect the intent of CMP316 WACM1 giving the following reasons:</p> <ul style="list-style-type: none"> <li>• Revised approach ensures individual sites' characteristics are recognised and charged consistently.</li> <li>• The inclusion of additional worked examples supports the intent.</li> </ul> <p>One respondent stated the legal text updates did not reflect the intent of CMP316 WACM1 adding the additional complexity introduced would outweigh the proposed benefits to CUSC parties. The same respondent noted the current methodology calculates the co-located site's TNUoS charge based on the pre-dominant technology. The respondent felt this would lead to co-located sites at risk of being charged higher than single type assets and therefore not cost reflective.</p>



**Panel Recommendation/Determination vote**

The Panel will meet on the 31 May 2024 to carry out their recommendation vote. They will assess whether a change should be made to the CUSC by assessing the proposed change and any alternatives against the Applicable Objectives.

**Vote 1:** Does the Original or WACM1 facilitate the objectives better than the Baseline?

**Panel Member: Andrew Enzor – User Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

**Panel Member: Andy Pace – Consumers’ Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

**Panel Member: Binoy Dharsi – User Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

**Panel Member: Christian Parsons - ESO Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

**Panel Member: Garth Graham - User Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						

WACM1						
Voting Statement						

**Panel Member: Joe Colebrook - User Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

**Panel Member: Joseph Dunn – User Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

**Panel Member: Kyran Hanks - User Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

**Panel Member: Paul Jones - User Panel Member**

	Better facilitates AO (a)?	Better facilitates AO (b)?	Better facilitates AO (c)?	Better facilitates AO (d)?	Better facilitates AO (e)?	Overall (Y/N)
Original						
WACM1						
Voting Statement						

**Vote 2 – Which option is the best?**

Panel Member	BEST Option?	Which objectives does this option better
--------------	--------------	--

		facilitate? (If baseline not applicable).
Andrew Enzor		
Andy Pace		
Binoy Dharsi		
Christian Parsons		
Garth Graham		
Joe Colebrook		
Joseph Dunn		
Kyran Hanks		
Paul Jones		

### Panel conclusion

Panel will meet on 31 May 2024 to carry out their recommendation vote.

### When will this change take place?

#### Implementation date

01 April 2025

#### Date decision required by

By 30 September 2024 as this is a Charging modification

#### Implementation approach

The ESO Billing system and the ESO Tariff Setting and Charging processes would need to be updated. Appendix C of the Connection Agreement will require updating.

ESO TNUoS Guidance note to be updated for industry participants to include co-located examples.

### Interactions

- |   |   |  |                                |
|---|---|--|--------------------------------|
| <input type="checkbox"/> Grid Code              | <input type="checkbox"/> BSC                              | <input type="checkbox"/> STC                 | <input type="checkbox"/> SQSS  |
| <input type="checkbox"/> European Network Codes | <input type="checkbox"/> EBR Article 18 T&Cs <sup>2</sup> | <input type="checkbox"/> Other modifications | <input type="checkbox"/> Other |

CMP316 should have no consumer TNUoS impact as the value recovered via TNUoS would be unchanged. The way the value is allocated across the generation community would change.

The proposed solution assumes that the mapping of fuel/technology types to the wider generation charging categories has already taken place (and will therefore cope with any future changes implemented if the mappings change over time).

There is no direct impact to the SQSS identified in this modification, however it is noted that the TNUoS Call for Evidence is looking to review links with the TNUoS methodology and SQSS.

<sup>2</sup> If the modification has an impact on Article 18 T&Cs, it will need to follow the process set out in Article 18 of the Electricity Balancing Regulation (EBR – EU Regulation 2017/2195) – the main aspect of this is that the modification will need to be consulted on for 1 month in the Code Administrator Consultation phase. N.B. This will also satisfy the requirements of the NCER process.

This modification only affects co-located generators. Non co-located generators will not be required to do anything differently as a result of this modification.

Through the work on this Modification, it is necessary to also change three Exhibits to the CUSC. The three Exhibits to be changed are: CUSC Exhibit B Connection Application (BCAs); Exhibit D BEGA Application; Exhibit I Modification Application – this is covered under [CMP397](#).

CMP393 is also proposing changes to the ALF calculation within CUSC Section 14, however these legal text changes should have no impact on the intent of CMP316.

## Acronyms, key terms and reference material

Acronym / key term	Meaning
ALF	Annual Load Factor
BMU	Balancing Mechanism Unit
BSC	Balancing and Settlement Code
CA <sub>P</sub> i	Maximum Capacity for Technology i
CEC	Connection Entry Capacity
Chargeable Capacity	Chargeable Capacity is the basis of the generation charge, where Local Annual Liability = Chargeable Capacity x Local Tariff
CHP	Combined heat and power
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
DRC	Data Registration Code
EALF	Effective ALF
EBR	Electricity Balancing Regulation
ESO	Electricity System Operator
GC	Generation Capacity
GWh	Gigawatt hours
MC	Maximum Capacity
MTPSECS	Multi Technology Power Station Effective Capacity Scaled
MTPSALFs	Multi Technology Power Station ALF (Annual Load Factor)
MTPSTEC	Multi Technology Power Station TEC for each technology
MTPSTEC <sub>Pk</sub>	Multi Technology Power Station TEC (Peak)
Mod App	Modification Application (to a Connection Contract)
MWh	Megawatt hours
NETS	National Electricity Transmission System
PV	Photo Voltaic
RC	Registered Capacity
SCR	Significant Code Review
SQSS	Security and Quality of Supply Standards
STC	System Operator Transmission Owner Code
T&Cs	Terms and Conditions
TDR	Transmission Demand Residual
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System
YRNS	Year Round Not Shared
YRS	Year Round Shared

**Reference material**

- None

**Annexes**

Annex	Information
Annex 1	Proposal form
Annex 2	Terms of reference
Annex 3a	CMP316 Workgroup consultation responses
Annex 3b	CMP316 Workgroup consultation summary table
Annex 4	CMP316 Legal text
Annex 5	WACM1 Alternative Form
Annex 6	CMP316 Workgroup Vote
Annex 7	CMP316 Indicative Cost Tool
Annex 8	CMP316 Examples for WACM
Annex 9	First Code Administrator Consultation responses
Annex 10	Workgroup Action Log (from Workgroup 12)
Annex 11	Second Code Administrator Consultation responses
Annex 12	Second Code Administrator Consultation