Workgroup Consultation

Removal of BSUoS charges from Generation

Overview:

This proposal seeks to modify the CUSC to better align GB market arrangements with those prevalent within other EU member states. This will deliver more effective competition and trade across the EU and so deliver benefits to all end consumers.

It is proposed that liability to pay Balancing Services Use of System (BSUoS) charges, which are currently charged to all liable CUSC parties on a non-locational MWh basis, is removed from GB Generators.

The Second Balancing Services Charges Task Force has now recommended that BSUoS should be paid by Final Demand which would be achieved by this proposal with an implementation date of 1st April 2023

Modification process & timetable

1. **Proposal Form** 30 October 2018
2. **Second Workgroup Consultation** 01 April 2021 - 26 April 2021
3. **Workgroup Report** 28 May 2021
4. **Code Administrator Consultation** 01 June 2021 - 22 June 2021
5. **Draft Modification Report** 30 July 2021
6. **Final Modification Report** 02 August 2021
7. **Implementation** 01 April 2023

Have 5 minutes? Read our Executive summary

Have 20 minutes? Read the full Workgroup Consultation

Have 30 minutes? Read the full Workgroup Consultation and Annexes.

Status summary: The Workgroup are seeking your views on the work completed to date to form the final solution(s) to the issue raised.

This modification is expected to have a: High impact for all GB BSUoS Payers

Governance route	Standard Governance Route	
Who can I talk to about the change?	**Proposer:** Simon Vicary, EDF Energy, Simon.Vicary@edfenergy.com	**Code Administrator Chair**: Joseph Henry joseph.henry2@nationalgrideso.com
How do I respond?	Send your response proforma to cusc.team@nationalgrideso.com **by 5pm on 26 April 2021**	

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Executive summary

The CMP308 workgroup are holding a Second Workgroup Consultation to reflect industry developments and updates to he Terms of Reference since the workgroup reconvened after the Second Balancing Services Charges Task Force.

What is the issue?

In our European trading partners and other interconnected countries, the equivalent charges for balancing activities are more commonly charged entirely on demand.

As a result, the wholesale prices offered by generators in interconnected countries will not reflect these costs in the same way as those offered by a GB generator. Our estimate is that GB generation was disadvantaged by the extra cost by approximately £600m in 2017.

Following the Second Balancing Services Charges Task Force, it was recommended that BSUoS should be paid by Final Demand. CMP308 was put on hold until the conclusion of this Task Force, but restarted as a vehicle to implement this recommendation with an expected implementation date of 1st April 2023.

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

Proposer's solution: This proposal seeks to modify the CUSC to align GB market arrangements with those prevalent within other EU member states. This will deliver more effective competition and trade across the EU and so deliver benefits to all end consumers. It will also further align treatment of transmission and distribution connected generation assets.
It is proposed that Balancing Services Use of System (BSUoS) charges, which are currently charged to all liable CUSC parties on a non-locational MWh basis, are removed from GB Generators. This will effectively better align the GB 'generation cost stack' with those in other EU markets, thus facilitating more equitable competition with generation in those markets which are not subject to such charges.

Implementation date: 1st April 2023

Summary of potential alternative solution(s) and implementation date(s):

No alternative solutions are proposed by the Workgroup

What is the impact if this change is made?

With sufficient lead time for implementation, our modelling indicates that the consumer impacts in the short-term are likely to be neutral.
In the long run removal of the identified distortion in the wholesale market would ensure more effective competition which is in consumers' interests: i.e. will ensure dispatch and investment in new generation is more efficient.

- Demand BSUoS will be less than double of current BSUoS £/MWh rates as interconnector flows to GB do not pay BSUoS (i.e. split of BSUoS between demand and generation is not currently 50:50), i.e. consumers neutral short term.
- Sufficient lead time of 2 years after a decision is made[1] to ensure:
    - wholesale market adjusts to the removal of BSUoS from generation
    - time for consumers and suppliers to adjust for change.
- Benefit of avoiding the need to factor BSUoS risk into generation/wholesale market costs, instead being covered within more predictable demand volumes.

Interactions

This modification has interactions with the Second Balancing Services Charges Task Force, and looks to satisfy the Task Force's recommendation on Deliverable 1 that BSUoS charges should be levied on Final Demand. There will also be interations with other modifications arising from the Second Balancing Services Charges Task Force, namely CMP361 and CMP362.

What is the issue?

In our European trading partners and other interconnected countries, the equivalent charges for balancing activities are more commonly charged entirely on demand.

As a result, the wholesale prices offered by generators in interconnected countries will not reflect these costs in the same way as those offered by a GB generator. Our estimate is that GB generation was disadvantaged by the extra cost by approximately £600m in 2017[2].

Why change?

Better aligning the GB market arrangements and the charges faced by GB generation with those prevalent in other interconnected countries, where generation is typically not subject to such charges, would allow GB and continental generation to compete on a more equitable basis and would remove the potential for BSUoS to distort cross border trade.

This proposal would also align BSUoS charging treatment between transmission and distribution connected generation and storage.

Ofgem broadly supported a similar proposal (CMP201) in 2014 but considered the short-term consumer negative impact outweighed the longer-term benefits:

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[1] Following the Second Balancing Services Charges Task Force the implementation date is now expected to be 1st April 2023

[2] This figure was current when the modification was raised. The ESO will produce an up to date figure ahead of the report going to CUSC Panel in May 2021.

“We consider that in principle, removing BSUoS from generators would have a small positive impact on competition. However, we are concerned that at this time the potential benefits this would bring would not be material enough to offset the potential costs to consumers from implementing the modification” – from Ofgem’s CMP201 decision document, October 2014.

However, NGET’s calculations, on which Ofgem’s decision was based, were that CMP201 would be detrimental to consumers in the short term. This did not take into account the impact of CMP202 (Revised treatment of BSUoS charges for lead parties of Interconnector BM Units), so:

- CMP201 modelling (for status quo) assumed BSUoS was split 50:50 between demand and generation.
- As a result of CMP202 the G:D split for BSUoS charging in 2017 was around 49:51 and is expected to be 47:53 by 2020.
- This reduces the cost increase for suppliers to a value that is roughly equal to the reduction in GB wholesale prices.

What is the solution?

Proposer’s solution

It is proposed that Balancing Services Use of System (BSUoS) charges, which are currently charged to all liable CUSC parties on a non-locational £/MWh basis, are removed from GB Generators. This will effectively align this part of the cost base that lies behind the GB ‘generation cost stack’ with that of generators in other EU markets, thus facilitating more equitable competition with generation in other markets which are not subject to such charges.
This proposal seeks to modify the CUSC to align GB market arrangements with those prevalent within other EU member states. This will deliver more effective competition and trade across the EU and so deliver benefits to all end consumers.

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In the FMR (Final Modification Report) for CMP201, a very similar proposal, National Grid indicated that there would be an impact on central IS systems to adjust revenue recovery to demand parties. They stated that this impact is likely to be relatively minor (less than £100k) and would not comprise a “critical path” item for implementation (assuming a minimum two year lead time for contractual reasons).

The ESO are proposing to deliver the BSUoS reform changes in 2023 as part of the new charging & billing solution, understanding the requirements for CMP308 and any other modifications proposed as part of BSUoS reform will form part of the critical path for designing the new system to ensure the methodology changes are built in early from the requirements and design stage in Q2 and Q3 FY22.

Also, in the CMP201 FMR no significant IS issues for Users were identified as part of the Workgroup consultation.

This modification has interactions with the [Second Balancing Services Charges Task Force](), and looks to satisfy the Task Force's recommendation on Deliverable 1 that BSUoS charges should be levied on Final Demand with an expected implementation date of 1st April 2023.

Workgroup considerations

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Also, in the CMP201 FMR no significant IS issues for Users were identified as part of the Workgroup consultation.

This modification has interactions with the [Second Balancing Services Charges Task Force](), and looks to satisfy the Task Force's recommendation on Deliverable 1 that BSUoS charges should be levied on Final Demand with an expected implementation date of 1st April 2023.

Workgroup considerations

The Workgroup convened 12 times to discuss the perceived issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Applicable Objectives.

The Workgroup held their first Workgroup Consultation between 05 April – 08 May 2019 and received 20 responses. The full responses can be found at Annex 4 of this consultation

The second Workgroup Consultation is being held as a result of developments since the first Workgroup Consultation and changes to the Terms of Reference, as highlighted in paragraph 5.2 of this consultation.

Consideration of the proposer's solution

1. Context – CMP201 and CMP202

1.1 What did CMP201 try to achieve?

1.1.1 *CMP201: Removal of BSUoS charges from Generation* was raised by National Grid Energy Transmission in October 2011. Like CMP308, CMP201 sought to remove BSUoS liabilities from Generation in order to bring GB Market arrangements in line with those prevalent within other EU member states. It was argued in the proposal for CMP201 that this would deliver more effective competition and trade across the EU and so deliver benefits to all end consumers.

1.1.2 The Proposer of CMP201 argued that removing BSUoS charges from generation would yield no adverse effects for GB end consumers, subject to implementation taking account of then existing contractual commitments. The argument was put forward that aligning the GB market arrangements with other member states better would facilitate an efficient functioning internal market in electricity and to that end, GB consumers would benefit from more competitive arrangements delivered through a wider fully functioning competitive market in generation.

1.1.3 After going through the standard CUSC modification procedure, CMP201 was rejected by Ofgem on 2 October 2014[3]. Despite rejection of the modification, Ofgem stated in this letter that they "firmly support the move towards more closely integrated European markets for electricity", and that "removing BSUoS from generators would have a small positive impact on competition"[4]. However, the Authority highlighted that the "potential benefits this would bring would not be material enough to offset the potential costs to consumers from implementing the modification". The Authority came to the conclusion that the short-term negative impacts to the market of implementing CMP201 would not be negated by the longer-term benefits of the modification at that point in time.

[3] Ofgem Decision Letter on CMP201 – 2 October 2014 - https://www.nationalgrideso.com/codes/connection-and-use-system-code-cusc/modifications/removal-bsuos-charges-generation

[4] Ibid, p1.

The modelling suggested that the costs to GB consumers could be between £200m - £250m per year (equating to £2.00-£2.50 increase in bills for the average domestic consumer) with an annual increase in generator profits of between £181m and £281m[5].

1.1.4 At the time CMP201 was raised, BSUoS charges were levied on a 50:50 split basis generators and suppliers. Generators would charge on their share of BSUoS charges to suppliers through the wholesale price and suppliers then pass the cost to the consumer through the retail price. The proposer and some workgroup members believe that the parameters in this scenario, under which Ofgem rejected CMP201, have now changed, leading for the need for the defect to be re-examined.

1.2 What has changed since CMP201?

1.2.1 CMP202 was raised by National Grid Electricity Transmission in December 2011 to remove BSUoS charges from interconnector Balancing Mechanism (BM) Units and Trading Units associated with interconnectors. This modification was implemented into the CUSC charging arrangements on 1 April 2013. The proposer of CMP308 believes that in 2017, the results of the implementation of CMP202 has shifted the balance of BSUoS G:D charging split was 49:51, and is expected to shift even further to demand, with a 47:53 split expected by 2020.

1.2.2 The Proposer revisited the findings of the CMP201 modelling and presented this to the workgroup. Although awareness of CMP202 was noted by the workgroup in the CMP201 report (as referenced in Annex 13) and Ofgem decision letter, the Proposer argued that an assumption of CMP201 was that BSUoS charges were at that time split 50:50 between production and demand. As mentioned in 1.1.6, following CMP202 the production volume from interconnection is no longer liable for BSUoS charges and thus this assumption no longer held. This assumption affects the modelled consumer impacts in the short-term identified by National Grid Transmission's modelling at the time. Revising this assumption means that the consumer impacts in the short-term are close to neutral, whereas Ofgem has seen this as negative in their assessment of CMP201. The longer-term benefits from more effective competition will remain[6].

The case for change has grown since CMP201:			
	Interconnection (GW)	Interconnection volume (TWh)	BSUoS (£/MWh)
CMP201 (2012)	3GW (2GW to mainland EU)	10	£1.51/MWh
Now (2017)	4GW (3GW to mainland EU)	16	£2.48/MWh
Future	c.8GW 2020 c.18GW early 2020s	30-70TWh (2021-2025)[1]	Growing

Figure 1 – Table produced by proposer illustrating case for change growing since CMP201

[5] https://www.nationalgrideso.com/document/6156/download, p4

[6] NGESO confirmed that throughout the modification analysis for CMP201, the work took into account the effects of CMP202. CMP201 was raised as a response to the intention to raise CMP202 so the effects were always considered throughout the process.

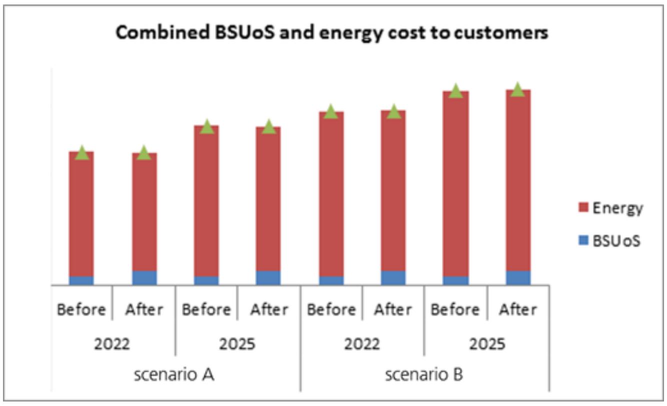

Figure 2: Proposer Analysis of Combined BSUoS and Energy Costs to Consumers (Long-Term Benefit)

1.3 Have the Consumer Benefits Changed Since CMP201 was rejected, and CMP202 was implemented?

1.3.1 In the initial discussions around the modification, the Proposer highlighted several consumer benefits of the modification. For our European trading partners and other interconnected countries, the equivalent charges for balancing activities are more commonly paid entirely by suppliers.

1.3.2 The proposer opined that as a result, the wholesale prices offered by generators in interconnected countries will not reflect these costs in the same way as those offered by a GB generator. The proposers estimate is that GB generation is disadvantaged by the extra cost of around £600m in 2017. The proposer set out his view that removing the costs from generation would hence better facilitate efficient competition between GB generation and generation in other interconnected markets.

1.3.3 The proposer stated that better aligning the GB market arrangements and the charges faced by GB generation with those prevalent in other interconnected countries, where generation is typically not subject to such charges, allows GB and continental generation to compete on a more equitable basis and removes the potential for BSUoS to distort cross border trade. By and large, similar points were made throughout the CMP201 process.

1.3.4 The proposer also highlighted that the modification supports the UK Industrial Strategy[7] which was not in place when CMP201 was rejected. The proposer also highlighted the EU “Third Package” aims to deliver all consumers greater choice with more cross-border trade so as to achieve efficiency gains, competitive prices and security of supply.

1.3.5 The workgroup revalidated the longer-term benefits used in CMP201 during the Workgroup process. Within the CMP201 Ofgem decision letter the following was stated:
We support the fundamental economic principle that increasing competition should lead to lower wholesale prices in the long run.
Specifically, in relation to longer-term impacts Ofgem made the following points:

[7] https://www.gov.uk/government/topical-events/the-uks-industrial-strategy

- *Higher profits for generators should encourage greater investment in GB generation – either in the form of new plant build or delayed closure/refurbishment of existing infrastructure;*
- *The increased investment would exert competitive pressure on the GB wholesale electricity price which would reduce or potentially eliminate the short-term increase noted above.*

1.3.6 Also, within the CMP201 Final Modification Report the following were highlighted, as a part of the EU Third Package, as important benefits for end consumers in the long term:

- *market prices should give the right incentives for investing in new generation;*
- *promoting fair competition and fostering new generation capacity in order to allow consumers to take full advantage of the opportunities of a liberalised market;*
- *fostering integration of their internal markets*
- *development of a true internal market through cross-border trade;*
- *Common rules for a true internal market that provides undistorted market prices, providing incentives for cross-border interconnection and new generation investment*

1.3.7 The proposer reiterated the benefits to both Industrial Strategy and Security of Supply as referenced in the report in section 3, page 5. After discussions the workgroup agreed that these potential benefits would still exist should CMP308 be implemented.

2. Analysis required to support CMP308

2.1 Recovery from Generation in Other European Countries

Recovery from Generation?	System Services						
	Primary reserve	Secondary reserve	Tertiary reserve	Congestion	Black start	Voltage control	System Balancing
Albania	No	No	No	No	No	No	No
Austria	No	Yes	No	No	No	No	No
Belgium	Yes	Yes	Yes	Yes	Yes	Yes	No
Bosnia and Herzegovina	No	No	No	No	No	No	No
Bulgaria	No	No	No	No	No	No	No
Croatia	No	No	No	No	No	No	No
Cyprus	No	No	No	No	No	No	No
Czech Republic	No	No	No	No	No	No	No
Denmark	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Estonia	No	No	No	No	No	No	No
Finland	No	No	Yes	Yes	Yes	Yes	Yes
France	No	No	No	No	No	No	No
Germany	No	No	No	No	No	No	No
Great Britain	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Greece	No	No	No	No	No	No	No
Hungary	No	No	No	No	No	No	No
Iceland	No	No	No	No	No	No	No
Ireland	Yes	Yes	Yes	Yes	Yes	Yes	No
Italy	No	No	No	No	No	No	No

Latvia	No	No	No	No	No	No	No
Lithuania	No	No	No	No	No	No	No
Luxembourg	No	No	No	No	No	No	No
Macedonia (FYROM)	No	No	No	No	No	No	No
Montenegro	No	Yes	Yes	No	No	No	Yes
Netherlands	No	No	No	No	No	No	No
Northern Ireland	No	No	No	No	No	No	No
Norway	Yes	Yes	Yes	Yes	Yes	Yes	No
Poland	No	No	No	No	No	No	No
Portugal	No	No	No	No	No	No	No
Romania	No	Yes	Yes	No	Yes	Yes	No
Serbia	No	No	No	No	No	No	No
Slovakia	Yes	Yes	Yes	No	Yes	Yes	No
Slovenia	No	No	No	No	No	No	No
Spain	No	No	No	No	No	No	No
Sweden	Yes	No	No	No	Yes	Yes	No
Switzerland	No	No	No	No	No	No	No

Figure 3: Balancing Charges Levied on Generation in Other European Countries

2.1.1 As Figure 3 illustrates[8], the current situation whereby BSUoS is charged on Generation in the GB market, albeit not unique in its specificity, is certainly in the minority when compared to other European Countries. In terms of GB arrangements, the only country which directly has the same arrangements is Denmark.

2.1.2 The majority of countries (26 out of the 36 illustrated above, or roughly 72%) charge no components of their balancing services charges equivalent on generation. In terms of electricity wholesale prices, this would place the GB wholesale market prices higher, ultimately impacting market participants and end consumers alike. This perceived disadvantage becomes even more pertinent when you consider the disparity between GB and some of our interconnected counterparts, such as the Netherlands and France. The latest report shows that for Ireland in 2019 System Balancing has been interpreted as being included in the Unit Transmission Tariff. This is a change from all previous publications but no explanation is provided in the report for the difference.
2.1.3 The workgroup were made aware of the Crown estates report 2018[9] which states that interconnectors exist or are planned to seven of our European neighbours. Of these, four (Belgium, Denmark, Norway and Ireland) pay balancing charges, including congestion (constraint) charges whilst three (Germany, Netherlands and France) do not. In none of the reports referenced has enough information been provided on other generator costs to enable a full holistic comparison of the cost stack. The table presented does not include Frequency Response which is one of the larger ancillary charges, and no view of connection charging regimes, subsidies such as CM or green taxes and levies have been mentioned, nor indeed the quality of the network being provided. In 2014,

[8] ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2018
https://docstore.entsoe.eu/Documents/MC%20documents/TTO_Synthesis_2018.pdf
[9] https://www.thecrownestate.co.uk/en-gb/media-and-insights/stories/2018-electricity-interconnectors/

system balancing charges in France were about one fifth of the UK charges[10] . One workgroup member feels a holistic comparison should be undertaken before making such a radical change to a charging regime.

2.1.4 - A workgroup member undertook some further analysis of the charges in markets at the end of these interconnectors, by looking at the information published by relevant TSOs. The aim of this was to understand how many of the TSOs charge producers on the basis of MWh output during a relevant trading period, as a charge which wasn't made in this manner could not be regarded as a Short Run Marginal Cost and could not be expected to interfere with wholesale market decisions. This is consistent with ACER's 2014 opinion on transmission tariffs which concluded that energy-based generation charges can affect the dispatch decision of generators by increasing the Short Run Marginal Cost of power plants, whereas power based charges for instance have no effect as the Short Run Marginal Cost remains unchanged[11]. The workgroup member concluded that that only two markets have something which is similar to BSUoS in how it is charged and that their rates are significantly below those in GB.

2.1.5 Following previous meeting's discussions on the Short-Term Marginal Costs being the key barrier to cross-border trade, rather than the longer term sunk costs, one workgroup member was keen to explore the option of changing the way Generators were charged BSUoS rather than removing the charge completely. A suggestion was to change generators BSUoS from the current volume (energy) based charge to a capacity (power) based charge. This idea was discussed and whilst it did appear to help resolve the market distortion and facilitate cross-border trade, addressing the defect raised, there was no clear means to implementation such a solution and the unintended consequences made it a less attractive proposition.

2.1.6 The proposer undertook analysis in order to calculate a £s Million figure to this perceived disadvantage. This figure, which is the BSUoS figure paid by GB Generators in 2017, was approximately £600m. The workgroup recognised that the actual lost opportunity cost would have been lower than this number, but it was concluded that this quantitative analysis would require support from specialist economic consultants with access to the appropriate market models taking into account other Short Run Marginal Costs, Long Run Marginal Costs and any relevant subsidies.. Two workgroup members stated, that in their opinion, this analysis would be necessary but the majority of the workgroup were happy to proceed on a principle based approach and did not consider the above analysis to be necessary.

2.2 Analysis of 2017 data, with and without the change implemented

2.2.1 As previously set out in the initial proposal, CMP308 seeks to remove the liability for BSUoS payments from generation. The thought process is to better align GB arrangements

[10] https://docstore.entsoe.eu/publications/market-reports/Documents/SYNTHESIS_2014_Final_140703.pdf).
[11] Paras 3.1.2 and 3.1.3 of "OPINION Of THE AGENCY FOR THE COOPERATION Of ENERGY REGULATORS No 09/2014 (15 April 2014) ON THE APPROPRIATE RANGE OF TRANSMISSION CHARGES PAID BY ELECTRICITY PRODUCERS"

to those which are prevalent in our European equivalents, which should in turn see a reduction in the wholesale energy costs charged by generators to suppliers in the GB energy market for Balancing Services. In order to establish the case behind the hypothesis of this proposal, the workgroup undertook various pieces of analysis.

2.2.2 The workgroup initially examined analysis undertaken by the proposer, which looked into BSUoS data from 2017 without the proposed change implemented (generation and demand still paying BSUoS), and BSUoS data from 2017 with the proposed change implemented (with only demand paying BSUoS) to see what the impacts would be. This Analysis can be found in full in Annex 1. The analysis shows that if the change had been implemented for 2017, the reduction in wholesale electricity prices does not need to be the full BSUoS £/MWh rate, which may be the case due to increased GB generation being at a higher marginal cost when offsetting changes in interconnector flows. With an efficiently operating market[12] this means that there would still be a consumer benefit manifesting itself in the total cost to the consumer in the short-term, unless the differential was greater than 15p a MWh. Two workgroup members highlighted the analysis from CMP201 as referenced in section 4.6.1 of this report, which may challenge the assumption that the differential referred to in 2.2.2 will be less than 15p a MWh.

2.2.3 One workgroup member believed that this Modification would adversely impact Interconnector business revenues thereby undermining business case for future interconnector build. However, the majority of workgroup members felt that removing a market distortion would contribute to the development of an efficient level of interconnection.

2.3 Analysis on likely effect of CMP308 on risk management costs and processes

2.3.1 A workgroup member put forward to the workgroup that although CMP308 is primarily focussed on removing a distortion to cross border trade, there is also an argument that it simplifies the processes needed to manage the risk that BSUoS imposes on the market in its current form, and therefore reduces the cost associated with this.

2.3.2 Figure 3 below shows in a simplified form how the market presently has to manage the unpredictability and risk associated with BSUoS. It shows that there are essentially three main points where participants may be required to do so. Firstly, suppliers have to forecast what BSUoS might be and reflect this in the prices and tariffs they set for their customers, often some considerable time in advance.

2.3.3 Secondly, generators are required to forecast what they believe BSUoS will be and reflect this in the offers they make into the energy market, as well as into the Balancing Mechanism and other balancing arrangements (such as TERRE in the future). They do so over different timescales and in different market mechanisms, so this part of the diagram actually reflects multiple market interactions. Finally, Suppliers may try to understand how energy prices and balancing related costs that they are exposed to, such as imbalance prices, will be affected by BSUoS being priced in by generators in this way.

[12] https://www.gov.uk/cma-cases/energy-market-investigation

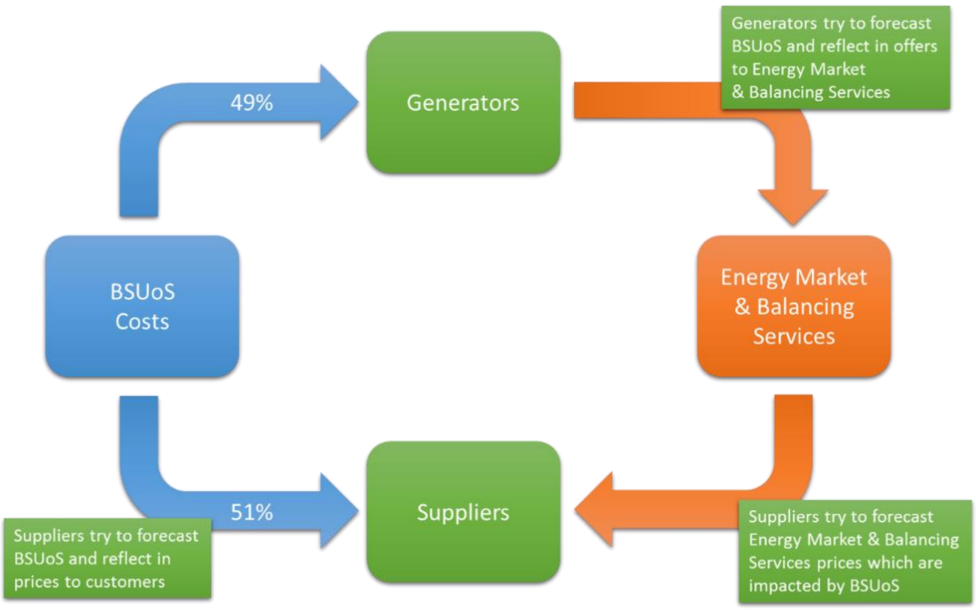

Figure 3: Present Charging of BSUoS

2.3.4 At all of these points, parties have to manage the risk associated with these transactions. This adds transaction costs as people and systems are required to carry out these functions. It should be noted, however, that feedback from supplier workgroup members suggest that some suppliers may not explicitly try to understand BSUoS impacts when forecasting energy and imbalance prices. What is clear from Figure 2, is that BSUoS costs ultimately find their way to suppliers and therefore customers, albeit some of it through a more complicated and indirect route via generators.

2.3.5 Figure 4 below shows the alternative situation should CMP308 be approved. Unsurprisingly, by charging 100 percent of the costs directly to suppliers, rather than a proportion being channelled indirectly to them through other market mechanisms, the processes are greatly simplified. Self-evidently, this should reduce overall transaction costs which will inevitably occur through the more convoluted process needed for the current charging regime.

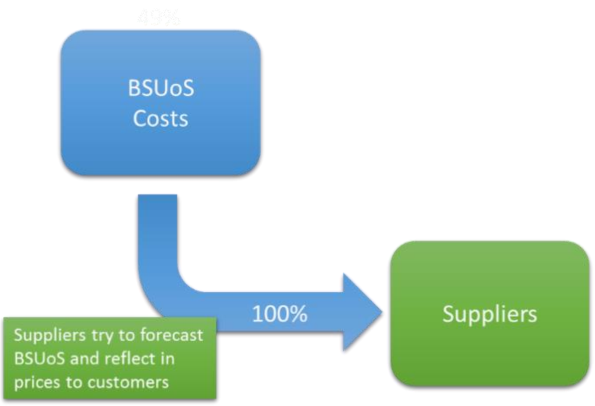

Figure 4: Charging of BSUoS under CMP308

2.3.6 The assessment process for CMP250 focussed on undertaking a quantitative analysis to estimate the savings in costs associated with lower risk premia. This proved problematic as it was difficult to obtain information on the risk premia that different parties applied in these circumstances. Given competition law restrictions and commercial confidentiality around this sort of information, or indeed that risk management processes might not actually involve choosing a defined risk premium, this is not surprising. However, the above analysis shows that on a qualitative basis CMP308 should provide cost reductions for the benefit of customers, by simplifying risk management processes across the industry as a whole. Although, some workgroup members were of the view that given the analysis only considers transaction costs associated with BSUoS forecasting (i.e. people and systems), any cost savings were likely to be negligible in the context of overall GB BSUoS costs.

2.3.7 In the opinion of one workgroup member, there is no real loss of efficiency were generators to become responsible for the full BSUoS risk rather than suppliers as this modification suggests, and offered an explanation, Currently, the generator portion of BSUoS is passed on to suppliers through the power markets. Suppliers do not need to take a view on this BSUoS cost since it forms part of the overall power price that they buy to hedge against the contract with the end consumer, and in this way pass all generator costs straight through to their customers. Suppliers purchase energy through the liquid market to hedge their risk – BSUoS is simply amalgamated with all the other generator costs e.g. fuel and is not treated separately. The Supplier element of BSUoS is currently the only non-hedgeable part of BSUoS for suppliers. In their opinion, in the same way the generator element of BSUoS is the only part of BSUoS which adds risk for generators; and hence the workgroup member considers that both parties would like the other to pay the whole of BSUoS so they are fully protected from this cost. The majority of the workgroup, did not share this view.

2.4 Impact of Supplier BSUoS Charge Increase under the Price Cap

2.4.1 Suppliers currently operate under two price cap regimes. For domestic customers with credit meters, Ofgem implemented the Default Tariff Cap from the 1st January 2019. For prepayment customers the Prepayment Price Cap came into effect on the 1st April 2017. At the beginning of every February and August, Ofgem publish the details of the cap for the forthcoming charge restriction period. The caps will provide allowances for wholesale costs and network costs (including BSUoS), as well as for other costs.

2.4.2 It is assumed that with the implementation of this modification and the subsequent removal of BSUoS charges from generators an immediate fall in forward wholesale prices would be felt. However, there can be no certainty that the wholesale prices will drop and remain at a level proportionate to the increase Suppliers will be subject to; and so, in the event the expected fall in wholesale prices does not occur there would be significant additional financial strain on Suppliers.

2.4.3 The BSUoS element of the Price Cap methodologies uses historical BSUoS charges to forecast the costs to Suppliers for the period ahead, and as such; should this modification be implemented there will be a lag period of more than one year before the current methodology would allow Suppliers to reflect the increase in their tariff prices.

2.4.4 Like any increase in wholesale, network, policy or other operating costs Suppliers react by revising their tariff prices to reflect the increase, but the current price cap methodologies do not allow for this. If the price cap calculation methodology remains unchanged any fall in forward wholesale prices will be reflected immediately in the Price Caps, but the increase in supplier BSUoS costs will not. This will create a clear disconnect between the costs that Suppliers face and the tariffs they are allowed to charge customers to recover those costs.

2.4.5 To summarise the material issue for Suppliers; any change in wholesale prices will be reflected in the retail price, and as such this would have no effect on a supplier whose hedging strategy mimics the wholesale price indexation in the caps. It does not matter how wholesale prices change in response to this modification, as any changes would be included in the price cap methodology. The point is that BSUoS costs for Suppliers would increase immediately following implementation, but the allowance for BSUoS costs will not increase immediately.

The influence of the cap would result in a suppression of retail prices, setting them below an economically efficient level that will force losses on efficient suppliers.

2.4.6 It would seem appropriate, following acceptance of this modification, and in advance of its implementation that Ofgem revise the methodology for the price caps to fairly reflect the inclusion of the increase in BSUoS charges Suppliers will be subject to. Should no such modification to the BSUoS methodology for the price cap be apparent prior to the Authority decision on this modification, the potential detrimental impacts on suppliers described above will need to be fully considered before approval or rejection.

2.4.6 The prepayment price cap is temporary, and is due to expire at the end of 2020 when the smart meter rollout is expected to complete. However, should this date be pushed back then the prepayment price cap may be extended and similar logic to above should be applied.

2.5 Analysis of Behind the Meter and Distributed Connected Generation Impacts of CMP308

2.5.1 One workgroup member undertook analysis in regards to the behind the meter impacts of CMP308, after discussion was held during the first working group. The CMP308 proposal will significantly increase the BSUoS charge faced by suppliers. Since CMP308 is based on net supplier demand, embedded generation and demand side response will reduce the liability for this charge, by reducing the overall metered demand of suppliers. In addition, some embedded generation and demand side response may be able to access BSUoS embedded benefits directly from the ESO based on the current BSUoS charging arrangements.

2.5.2 The workgroup discussed the potential impact of CMP308 on the incentives for parties to operate embedded generation and demand side response on sites connected to the distribution system. Such sites include generation that is effectively “behind the settlement meter” whereby the effect of the generator output or demand side response is seen on a net basis at the settlement meter. While CMP308 will increase the overall

BSUoS offset for suppliers, the incentive to generate will be driven by the power price that is avoided by the supplier (the avoided cost for the supplier).

2.5.3 Since BSUoS is a half hourly charge it is expected that in an efficient market the power price will reduce as a direct consequence of the increase in BSUoS charge for suppliers for each half hour. Therefore, a reduction in the power price will offset any increase in the BSUoS liability of a supplier. Consequently, the workgroup concluded that CMP308 would have a neutral impact on the incentives for parties to operate embedded generation and demand side response on sites connected to the distribution system.

2.5.4 The provider of this analysis stated their belief that this conclusion is based on the assumption that the market operates efficiently and that the reduction in the half hourly power price will always offset the increase in the supplier's liability for BSUoS. The workgroup discussed whether there was any evidence that the market would not operate efficiently in this case. A number of issues that could impact efficiency include

- the contracting strategy of the suppliers (hedged over different timescales which will include an averaging of the costs associated with BSUoS);
- the access to the power market for embedded generation and demand side response on customer sites; and
- the visibility of half hourly prices.

2.5.5 Most embedded generation and demand side response is contracted through Suppliers. At some sites, Suppliers may provide for half hourly spill or top up costs so it is difficult to identify any systematic impact of the proposed change. At other sites BSUoS costs will be forecast by Suppliers and passed through on average to customer sites. Consequently, CMP308 may create gains in some half hours for embedded generation and demand side response and losses in other half hours. However, the impact is likely to be neutral overall having taken into account these effects.

2.5.6 The increase in BSUoS embedded payments to £4.80/MWh leads to an assumed offset by a wholesale market price decrease. These figures supported the Proposer's idea that the embedded credit increase would be mitigated by the wholesale market decrease if the change was to be implemented into BSUoS charging arrangements.

2.5.7 The BSUoS Embedded Benefit is the difference between BSUoS paid by transmission-connected generators and credited to distribution-connected generators as BSUoS is charged on net volume. This credit received by embedded generators is usually equal and opposite to the charge paid by transmission-connected generators. Whilst BSUoS payments to embedded generators will increase, it will be by the same amount that the payments from transmission-connected generators reduce. The BSUoS Embedded benefit, which is in scope of the Targeted Charging Review, is reduced by £0.15/MWh so is largely unchanged, based off analysis by the proposer.

2.5.8 Following on from these considerations, CMP333 was raised and implemented and consequentially demand will be charged on a gross basis. The workgroup acknowledged this, but have illustrated these conversations to give context to this report.

3.0 Wider Industry Developments

3.1 First Balancing Services Charges Task Force

3.1.1 Ofgem has asked the Electricity System Operator (ESO) to launch a Balancing Services Charges Task Force under the Charging Futures arrangements to provide analysis to support decisions on the future direction of Balancing Services Use of System charges (BSUoS). In particular, the Task Force was asked to examine the potential for and feasibility of some elements of balancing services charges being made more cost-reflective and hence provide stronger forward-looking signals.

3.1.2 The Task Force work was carried out with the assessment of CMP308. The workgroup for CMP308 were advised to keep a close eye on the outputs of the Balancing Services Charges Task Force. There are some members of this workgroup who are also Task Force members.

3.1.3 The proposer has frequently reiterated his wish that this modification be considered in a similar timeframe by the Authority as the outputs of the Task Force. However, the distinction between the two pieces of work are quite clear: the scope of the Task Force is looking at separate elements of the BSUoS cost and whether there can be a forward-looking signal, whereas the modification addresses the defect of uncompetitive charging between GB and European generators.

3.1.4 During the consultation period, the Balancing Services Charges Task Force published their draft conclusions. Their consultation on the draft report[13] closed on 17 May 2019, and the workgroup had time to consider the draft report, and in some instances, provide input to the consultation. The final conclusions report was published on 31 May 2019. [14]

3.1.5 The Conclusions of the Task Force were that the current BSUoS charge, “does not currently provide any useful forward-looking signal which influences user behaviour to improve the economic and efficient operation of the market”[15] The Task Force identified five principle factors as to why this is the case, namely that the current BSUoS charges are “hard to forecast, complex, increasingly volatile, that other market signals are more material and so take precedence, and the current BSUoS charge applies to all chargeable users of the transmission system on an equal basis”[16].

3.1.6 The Task Force continued their work by looking into the individual elements of the BSUoS charge, and whether they had the ability to become more forwards looking and cost reflective. The elements highlighted for further development were locational transmission constraints; locational reactive and voltage constraints; response and reserve bands; and response and reserve utilisation. Other elements were discounted on a meritocratic basis at this point.

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[13] http://www.chargingfutures.com/media/1330/balancing-services-charges-task-force-draft-report.pdf
[14] http://www.chargingfutures.com/media/1348/balancing-services-charges-task-force-final-report.pdf
[15] Ibid, p4
[16] Ibid, p4

3.1.7 Further work into the four identified options was undertaken but "theoretical advantages to all four potential options identified, the implementation of each of these would not or could not provide a cost-reflective and forward-looking signal that would drive efficient and effective market behaviour"[17].

3.1.8 The conclusion of the Task Force was that "it is not feasible to charge any of the components of BSUoS in a more cost-reflective and forward-looking manner that would effectively influence user behaviour that would help the system and/or lower costs to customers. Therefore, the costs included within BSUoS should all be treated on a cost-recovery basis"[18].

3.1.9 The workgroup considered the findings of the Task Force as part of their work, but ultimately the workgroup is concerned with which user group pays BSUoS charges, as opposed to how they are recovered. The workgroup has sought further reassurances that this modification will not be looked at in isolation, but in conjunction with other modifications and charging initiatives ongoing in industry at this point in time.

Second Balancing Services Charges Task Force

3.1.10 The Second Balancing Services Task Force was launched by the ESO in January 2020, in response to Ofgem's request of 21st November 2019, and built on the work of the First Balancing Services Task Force (Jan 2019 – May 2019). The initial timelines specified by Ofgem required the Final Report to be submitted by the Task Force in June 2020. Following the disruption caused by COVID-19 Ofgem decided to pause the Task Force's work pushing the submission date of this Final Report back to September 2020.

3.1.11 The Task Force had two deliverables to consider: 1) Who should be liable for Balancing Services Charges, and; 2) How these charges should be recovered.

3.1.12 On Deliverable 1, who should pay, the Task Force recommend that "Final Demand" should pay all Balancing Services charges, subject to sufficient notice to industry prior to implementation.

3.1.13 On Deliverable 2, how should the charge be levied the Task Force have concluded that a volumetric fixed BSUoS charge would deliver overall industry benefit, and that the total length of the fix and notice period should be around 14/15 months in length. There was extensive debate whether the charge should be similar to the Transmission Demand Residual methodology (i.e. £/site, based on size) or volumetric (i.e. £/MWh).

3.1.14 The Task Force discussions are laid out in a table in the final report which shows assessment of each approach against the TCR principles. Ultimately, the distributional impacts of a banded charge and the complexity it introduces led The Task Force to agree by majority that the most appropriate way of recovering the charge is through a volumetric (£/MWh) charge. This is particularly relevant for a charge which is recovering costs related to an energy service.

[17] Ibid, p5
[18] Ibid, p5

3.1.15 Fixing BSUoS charges ex ante requires the ESO to manage the volatility risk on behalf of BSUoS payees for the duration of the fix period. It is the Taskforce's view that the BSUoS tariff would be fixed so all payees know the £/MWh fixed tariff in advance and the ESO carries any cost not covered by the fixed fees as no party knows exactly how much Balancing Services expenditure will be over the period. This creates an over/under recovery risk, and associated cash-flow costs, for the ESO to manage. The Task Force recognised a compromise needed to be made between certainty for suppliers and shortfall minimisation for the ESO.

3.1.16 This led to a recommendation for a 14/15-month total fix and notice period. Notice to industry of the changes to the methodology is important; the Task Force recommend that two years' notice from the point of Ofgem's response is given, this notice period would include notice of the fixed charge such that tariffs begin on 1st April two years after Ofgem's response. The Task Force noted that it's important that Ofgem's response gives clear indication on the future BSUoS arrangements. The Task Force's conclusions and the reasoning given in this accompanying report will be reviewed by Ofgem to determine the next steps for changes to the Balancing Services charging methodology.

3.1.17 The Task Force's recommendations for further work in this area are:

- to revisit the CMP201 analysis to understand whether the conclusions still hold. This analysis should include the impacts on other markets (capacity market, balancing mechanism, the treatment of interconnector congestion revenue etc.) and explore both present and potential future market structures, as these were not considered under CMP201;
- to identify a suitable combination of fix and notice period for the BSUoS tariff through quantitative analysis of supplier risk management and ESO financing;
- to form a BSC issues group after the conclusion of the CUSC modifications which will implement Ofgem's decisions and investigate changes to the RCRC mechanism in light of the Task Force's recommendations and Ofgem's subsequent decisions and;
- to consider distributional impacts including to energy intensive users and vulnerable consumers.

3.1.18 The CMP308 workgroup was recommenced in January 2021 in order to deliver against the Task Force's recommendation around who should pay Balancing Services Charges. The workgroup is cognisant that the ESO will be raising other modifications to deal with the recommendations outlined around how the BSUoS Charge should be constructed.

3.2 CMP281 – 'Removal of BSUoS Charges From Energy Taken From the National Grid System by Storage Facilities'

3.2.1 CMP281 was raised by Scottish Power in July 2017 and aims to remove liability from storage facilities for Balancing Services Use of System (BSUoS) charges on imports. This modification was relinquished by Scottish Power in November 2018 and adopted by Engie. Both the previous and current proposer of this modification sit on the workgroup for CMP308.

3.2.2 In terms of progress of the modification, the Industry were consulted on CMP281 in October 2019. The workgroup is well developed and has been ongoing for some time. The question as to whether the solution should encompass Supplier Volume Allocation as well as Central Volume Allocation had proved somewhat problematic. However, after discussions within the workgroup, a SVA solution is also being developed to complement the CVA allocation, following discussions with the Authority.

3.2.3 In their open letter on storage and charging reform, Ofgem stated that CMP281 "would appear to broadly align with our stated principles, insofar as BSUoS is a cost recovery charge. But we expect the workgroup to monitor the outcomes of the BSUoS Task Force closely"[19]. As such, the CUSC Panel in January 2019 stated that the report from the Workgroup should not come back before the Task Force concludes. The workgroup for CMP308 will be aware of developments in CMP281 and would expect Ofgem to make a decision on the modifications in line with the ongoing work of the Task Force as outlined in paragraph 3.1 of section 4 of this report.

3.3 Targeted Charging Review

3.3.1 The Targeted Charging Review (TCR): Significant Code Review (SCR) is an Ofgem-led project that assesses how residual network charges should be set and recovered in Great Britain, including BSUoS "Embedded Benefits" received by distribution-connected generators. In August 2017, Ofgem launched the TCR to address their concerns that the existing framework for residual network charges could lead to inefficient use of the network, leading to adverse impacts on consumers. Ofgem have confirmed that CMP308 does not fall into the scope of this work.

3.3.2 When this modification was raised by EDF Energy, concerns were expressed in industry as to whether this modification would have an overlap with the work within both the TCR and the then upcoming Balancing Services Task Force. Ofgem wrote to the CUSC Panel chair on 24 November 2018 advising that they believed the CUSC Panel and the proposer should consider discontinuing work on CMP308 until the outcome of the Balancing Services Task Force, the report of which would be considered closely within the work of the TCR[20].

3.3.3 When the CUSC Panel considered this letter from the Authority at its meeting in November, it was made clear that they could not advise the proposer to withdraw and there was support from Panel members to continue work on CMP308, albeit not unanimously. As such, the workgroup has convened and progressed. The workgroup have considered the TCR throughout its workings.

3.3.4 In December 2019, Ofgem published their final decision on the Targeted Charging Review[21]. Ofgem has decided that:

[19] https://www.ofgem.gov.uk/system/files/docs/2019/01/storage_and_charging_reform_2201f.pdf

[20] https://www.ofgem.gov.uk/system/files/docs/2018/11/cmp308_letter_on_continuation_of_the_mod.pdf

[21] Ofgem Final Decision on Targeted Charging Review SCR

i) Residual charges will be levied in the form of fixed charges for domestic and commercial demand users only.
ii) The Transmission Generation Residual will be set at zero therefore transmission generators will no longer receive the current negative residual charge.
iii) Balancing Services Charges will be charged to Suppliers on a gross basis, which will remove the "Embedded Benefit" for distributed generators.
iv) A Second BSUoS Task Force will take place to consider who should pay Balancing Services Charges and how should the charges be recovered.

3.3.5 The workgroup note that as a result of the Targeted Charging Review, CMP333 "BSUoS – Charging Supplier Users on Gross Demand – TCR" was proposed and is due for implementation in April 2021. The workgroup will be factoring in the implementation of this modification to the work on CMP308.

3.3.6 The Second Balancing Services Task Force was launched by the ESO in January 2020, in response to Ofgem's request of 21st November 2019, and built on the work of the First Balancing Services Task Force (Jan 2019 – May 2019). Its findings are outlined above.

4.0 Post First Workgroup Consultation Discussions

4.1 Consideration of the Responses

4.1.1 The Workgroup convened on 30 May 2019 to consider the outcomes and responses of the Workgroup Consultation. The consultation responses are documented in Annex 4 of this report. Several talking points in regard to the modification were raised, and discussed at length. The workgroup noted that during a period of much Industry change, to receive the volume of responses was encouraging and thanked all respondents for their input.

4.2 Retail Price Cap Issues

4.2.1 The workgroup considered some responses which highlighted that the retail price cap could potentially have a detrimental impact on the progression of this modification. Prior to the Workgroup Consultation, discussions were held regarding how the domestic price cap utilised historic BSUoS charges to forecast the potential levels of BSUoS included in the price cap. If the modification was to be implemented, without adjustment to the basis of the BSUoS forecasting, it would no longer produce a representative forecast of BSUoS charges, causing a distortion in what costs suppliers must pay, as opposed to what they are able to recover from consumers under the new retail price cap. This is because suppliers actual BSUoS costs would be based on charges derived utilising the demand BSUoS charging base only, whereas the price cap allowance would be based on charges derived utilising the historic demand and generation BSUoS charging base.

4.2.2 One workgroup member had indicated in their response that it was their belief that issues around the price cap may have to be resolved first for this modification to prove effective, otherwise there could be potential issues further down the line. The example was given that although the forecasts would reflect the changes brought about by this modification, the costs to suppliers would not necessarily reflect this, causing a distortion in what costs suppliers must pay, as opposed to what they are able to recover from consumers under the new retail price cap.

4.2.3 Whilst other members of the workgroup expressed agreement with this viewpoint, the proposer and others believe that this issue was addressed in this report prior to the Workgroup consultation, and that the workgroup were merely revisiting an issue which had been discussed. The difference in opinion was noted and may be developed further within the workgroup process.

4.3 Implementation – Impact of Contractual and Commercial Arrangements, and potential Gains and Losses because of CMP308

4.3.1 The workgroup considered whether the proposed implementation timescales were correct, because various responses to the consultation suggested that both shorter and longer timescales would be more applicable. There was discussion held within the workgroup in regards to whether 3 years was indeed a more feasible option, due to the likelihood of some suppliers having locked in contracts with costumers (especially in the I&C market) out to three years, and as such, may not have sufficient risk premia in those contracts to cover any shortfall or detriment occurring due to the implementation of this modification.

4.3.2 Whilst concerns of this nature were noted, some workgroup members suggested firstly that 3-year contracts would not make up a significant proportion of fixed price contracts. It was also noted that contractual arrangements were not an issue unique in their specificity to demand users and suppliers only, but that there would be issues also around generation contracts..

4.3.3 One workgroup member commented that, in their opinion, conventional generation contracts would see gains and suppliers or contracted end consumers see losses in the event of insufficient notice of the change being given. Under current arrangements, a forecast of BSUoS would be incorporated within the price between the supplier and the generator when the initial energy purchase took place. This Modification Proposal would mean that the Supplier is liable for the cost of the generation side of BSUoS, for which they believed an allowance had been factored into the price of the power they purchased. In their opinion and experience, this supply business workgroup member believes that three year contracts are far from exceptional and are quite commonplace and, it is only 4 and 5 years out where the materiality of these contracts tails off. In their opinion, the suppliers will be locked in with contract reopening with customers unlikely for a number of reasons and similarly will not be able to reopen contracts with generation as mentioned previously.

The workgroup member would be happy to share further analysis with Ofgem, and believes that figures show the supplier windfall losses three years out would exceed the benefits quoted.

The majority of the workgroup disagreed with this view as they believe that prudent market participants would factor in regulatory and other risks to contracts that far out to minimise their exposure.

4.3.4 One workgroup member iterated their concern regarding what impact any implementation may have on cross border trade and any impacts on any contracts that may be in place in that area of the Industry. The rest of the workgroup noted that whilst the EU Third Package arrangements recognise that different types of market organisation will exist within the wider internal market in electricity, they also acknowledge the need to reduce market distortions to deliver the full benefits of a competitive internal market in electricity. In the workgroup members view, aligning the GB market arrangements with our European trading partners and other interconnected countries better facilitates an efficient functioning internal market in electricity. To that end, GB consumers will benefit from more competitive arrangements delivered through a wider fully functioning competitive market in generation. With sufficient lead time for implementation there should not be any impacts on any contracts that may be in place in that arena of the Industry, but the concern was noted by the workgroup and this may be something Ofgem could look in to in the case of CMP308 being implemented.

4.3.5 When the CMP308 workgroup reconvened after the outcome of the Second Balancing Services Charges Task Force, it took into account the Task Force's recommendation that there should be a two year notice period in regards to implementation. As such, the Workgroup are proposing implementation on 1 April 2023 in order to give the industry sufficient notice and time to adjust to the changes resultant of CMP308, and in line with the view indicated by Ofgem in its response to the Task Force's final report.

4.5 CMP201 and Consumer Impacts

4.5.1 Concerns were expressed in some of the consultation responses and by two workgroup members about the limited analysis presented on consumer impacts. Removing BSUoS from generation would reduce the GB generation cost stack and have an equivalent downward effect on wholesale prices. However, this would make GB generation more competitive and so would lead to increased 'domestic' generation (reduced imports and increased exports) which would have an upward effect on wholesale price as more expensive marginal plant came on. In the opinion of two workgroup members, whilst this upward effect on wholesale price would be less than the downward effect from the removal of BSUoS (i.e. wholesale prices would still be lower compared to the status quo), it would nonetheless benefit all GB generation and lead to additional generator profits and higher net consumer costs in the short term. In the opinion of two workgroup members, Annex 13 of CMP201 Final Modification Report paragraphs 16-20 support this. However, the majority of workgroup members believe this is mitigated by an appropriate implementation time.

4.5.2 . In the opinion of two workgroup members, in the longer term, these higher profits could lead to more investment and/or lower CM bids – potentially offsetting the short-term detriment. It was noted that CMP201 attempted to provide quantitative analysis for these short-term impacts.

4.5.3 The proposer has provided analysis, based only on historic data to avoid any breach of Competition Law, to show that the short-term impact referred to in CMP201 would only occur if the fall in the wholesale price was less than 95% of BSUoS. However, it was noted by two workgroup members that the summary of the analysis produced for

CMP201[22] estimated that, due to the effect described above, the net fall in wholesale price would be around 50% of the level of BSUoS removed from Generation.

4.5.4 However, the majority of workgroup members considered that this would be an unlikely outcome due to the competitive nature of the GB wholesale electricity market and expect most if not all of the BSUoS cost reduction to be passed through to GB consumers in GB wholesale electricity market prices.

4.6 Credit Cover Issues

4.6.1 It was highlighted within the workgroup that up until this point, credit requirements were not clear within the analysis undertaken. It was suggested by one workgroup member that it would be effective to work out what the total magnitude of the costs would be. It was also argued however that this could be over accounted for, but it wouldn't skew it one way or the other.

4.7 Revenue from BSUoS actions an Ancillary Service Provisions

4.7.1 The working group considered the interaction between market participants receiving revenue from BSUoS actions taken to balance the system, ancillary service provisions, and whether this receipt of payment would alter the risk premia of generators in relation to how this is managed by suppliers. The WG felt that there was insufficient evidence to demonstrate that this was the case.

5.0 Workgroup Discussions – Re-establishment of workgroup

5.1 Re-establishment of Workgroup

5.1.1 In November 2019, CMP308 was placed on hold until the Second Balancing Services Charges Task Force concluded. Following the Output of the Second Balancing Services Charges Task Force, the CMP308 workgroup reconvened to complete work on the modification, on the understanding that the recommendations of the Task Force were to be implemented using the CUSC modifications Process. CMP308 would be used as a vehicle for delivery against the Task Force's recommendation that Final Demand should pay Balancing Services Charges.

5.1.2 The ESO considered combining the workgroups for CMP308 and CMP361 as the legal text changes for both modifications impact the same section in the CUSC (14.29 & 14.30). Upon further consideration it was realised that the CMP308 legal text solution could be done separately from CMP361. The ESO suggested to run the two workgroups independently and submit CMP308 to the Authority once complete to provide early notice and clarity to impacted stakeholders.

5.2 Terms of Reference

[22] See Annex 13 of CMP201 Final Modification Report, specifically the table in A13.22

5.2.1 The workgroup recognised that post developments which occurred during its period on hold, that additional Terms of Reference, and subsequently a second Workgroup Consultation, would be required. These additional Terms of Reference were:

- Take into account the work undertaken on CMP281, CMP333 and the Targeted Charging Review
- Cross Code Interactions, in particular interactions with the BSC driven by Data Requirements
- Consideration of definition of Final Demand, in reference to CMP261and BSUoS billing
- Consideration of Ofgem's view on the Second Balancing Services Charges Task Force recommendation of 1st April 2023 implementation and any further views expressed by Ofgem on the future of BSUoS Charging

5.2.2 CUSC Panel agreed that these Terms of Reference should be added and the workgroup accepted this. The updated Terms of Reference are available at Annex 2 of this report.

5.2.3 The Workgroup is cognisant that these Terms of Reference are material, and as such it would be prudent to consult on this modification for a second time. As such, this document provides Industry with the opportunity to input on CMP308 taking into account the wider developments in industry which have occurred since the previous Workgroup Consultation.

5.3 Implementation Date – Removal of Proposed Alternates

5.3.1 Prior to the recess of the CMP308 workgroup, there had been concern from several workgroup members around the implementation date of CMP308, and whether there would be enough time afforded for industry to adjust to the change, both from the perspective of risk premia being removed from the wholesale price, and whether suppliers would be able to allow for this in future contracted positions with end consumers. Several workgroup members indicated a desire to raise alternatives which would give sufficient lead time for the market to adjust.

5.3.2 The Second Balancing Services Charges Task Force recommended that 2 years notice of this change should give the market adequate time to adjust. The workgroup acknowledged this by majority and stipulated that they would work towards CMP308 being implemented in April 2023, which gives over 2 years notice from the conclusion of the Second Balancing Services Charges Task force.

5.3.3 Subsequently, the proposed alternatives which would have gave either 2 or 3 years lead time were removed for consideration by the workgroup and workgroup members felt that this issue had been negated.

5.4 Analysis

5.4.1 The workgroup noted that Ofgem had stated in their response to the Second Balancing Services Charges Task Force that there would be quantitative analysis in regards to the impact and costs/benefits of CMP308. Ofgem advised the workgroup that the procurement process was underway to appoint external analysts to undertake this work, with confirmation on this due in the coming months, and work to start on this in April 2021. The workgroup noted the validity of the previous analysis undertake by EDF in the earlier stages of this modification.

5.5 Consideration of Final Demand

5.5.1 In their consideration of Final Demand, the workgroup noted several industry developments. Firstly, the workgroup considered the definition of Final Demand as given in CMP334, which defined Final Demand as "***electricity which is consumed other than for the purposes of generation or export onto the electricity network".***

5.5.2 The Workgroup also took noted that Ofgem, in their 2019 decision letter on the Targeted Charging Review[23], set out the rationale for residual network charges (which are also cost-recovery charges), being paid by Final Demand consumers.

5.5.3 The consideration taken to Final Demand by the workgroup also involved further discussion and recognition that the implementation of CMP333 (charging suppliers BSUoS based on Gross Demand[24]), introduces the principle of gross demand charging to BSUoS, and that any CMP308 solution should follow on from CMP333. A workgroup member conducted some analysis on how the solution for CMP308 could look after CMP333 is implemented, included in Annex 5. Please see below figure.

<u>Current Situation (Baseline)</u>	**Net Direction of Trading Unit/Base Trading Unit**	
Direction of BM Unit	**Offtaking (importing)**	**Delivering (exporting)**
Offtaking (importing)	**Pays**	**Credit**
Delivering (exporting)	**Credit**	**Pays**

[23] Ofgem Final Decision on Targeted Charging Review SCR
[24] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp333-bsuos

CMP333 and CMP308

Type of BM Unit	Direction of BM Unit	Basis of charging	CMP308
Transmission Connected Generators		As Baseline*	No liability
Embedded Generators with BEGA and not Exempt Export BM Units		As Baseline*	No liability
Transmission Connected Demand		As Baseline*	Pays on Final Demand
DNO Connected Demand Sites (Supplier BM Units)	BM Unit Gross Demand is positive (gross import)**	Pays	Pays on BM Unit Gross Demand as per CMP333, minus station load for embedded generation in Supplier BM Units ****
	BM Unit Gross Demand is zero	No liability	
Exempt Export BM Units	Offtaking (importing)	Pays***	No liability
	Delivering (exporting)	No liability***	

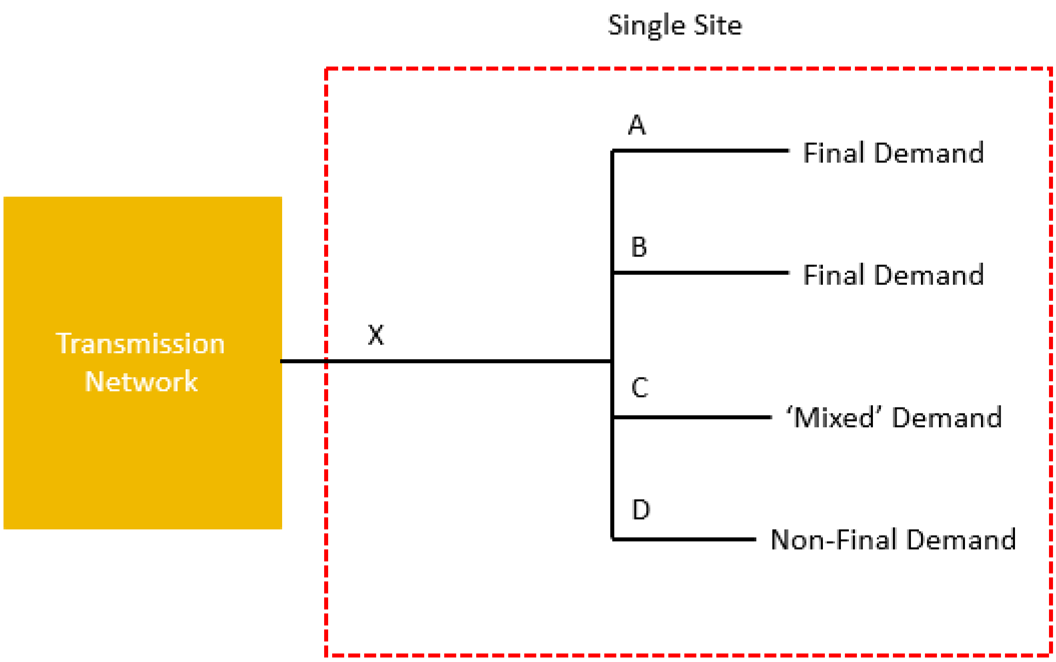
5.5.4 The workgroup also gave consideration in its discussions around a solution to the implications of CMP281, and associated BSC Modification P383 in regards to BSUoS charges being exempt for storage. The ESO noted that this solution introduces declaration process to demonstrate exemption from BSUoS liability, and suggested that this could be extended to final demand.

5.5.5 The workgroup are also cognisant that there will be an upcoming TNUoS Demand Residual and Complicated Sites CUSC modification (CMP363/4) to addresses treatment of complex sites and metering configurations, reviewing and extending the declaration process introduced under CMP281/319. It was noted that, by using the existing BMU charging approach and CUSC Final Demand definition, the CMP308 solution is expected to align with this modification.

5.5.6 The ESO suggested (in regards to the legal text for the original solution) a minimal change to CUSC legal text to allow CMP308 to be submitted for decision ahead of other BSUoS Reform mods, which would involve reusing/ amending definitions introduced for CMP333 in a final demand context: SGQM & TQM. The ESO have noted feedback from the workgroup in regards to this and are reviewing this suggestion.

5.5.7 The ESO also provided a Case Study in regards to this, please see below figure:

The below figure aims to test whether the application of charging BSUoS to Final Demand BMUs is consistent regardless of the metering configuration of the example site. The workgroup discussed that for the purpose of BSUoS charging Non-Final Demand on a mixed site could only be excluded if it could be identified as a Non_Final Demand BMU. Otherwise, mixed sites will be charged BSUoS on the boundary point (point X in the below figure).



5.6 Data Requirements/Potential BSC Modification

The workgroup discussed how to obtain and apply Final Demand Data for the purpose of BSUoS billing. Final Demand has been introduced to the TNUoS demand residual through CMP344.

Applying final demand to BSUoS is an opportunity to align BSUoS and TNUoS billing. At this moment discrepancies have become apparent that require additional change and processes to be introduced to obtain the final demand data required for BSUoS billing.

TNUoS demand residual Final Demand data is currently not sufficient for the purpose of BSUoS billing as the residual is charged on a £ per site per day basis as a banded charge. BSUoS is charged on a BMU level and requires half hourly data.
We expect that over time the Final Demand application to BSUoS and TNUoS charging will converge.

5.6.1 Overview of Discussions on Data and Final Demand

5.6.1.1 Applying Final Demand to BSUoS charging required clarification on how the definition is applied. Charging Final Demand for BSUoS purposes means that BMUs are charged on a gross volume basis and any metered volumes associated with SVA facilities classed as Non-Final Demand with a valid Declaration (Electricity Storage Facilities, Electricity Generation Facilities, Eligible Service Facilities) or metered volumes associated with CVA BMUs with a valid Declaration (Electricity Storage Facilities, Electricity Generation Facilities, Eligible Service Facilities) are excluded.

5.6.1.2 A range of options were discussed on which processes may be required to implement CMP308. One question discussed was which party is best suited to know whether a site or BMU is Final Demand/ Not Final Demand.
Suppliers are liable for paying BSUoS bills on behalf of their portfolio and have an interest to understand and exempt Non Final Demand sites from the charge.
DNOs have an enduring relationship with sites that doesn't end when a customer changes supplier.
Often, a supplier will inform the DNO that a site/ facility does not fall under Final Demand.

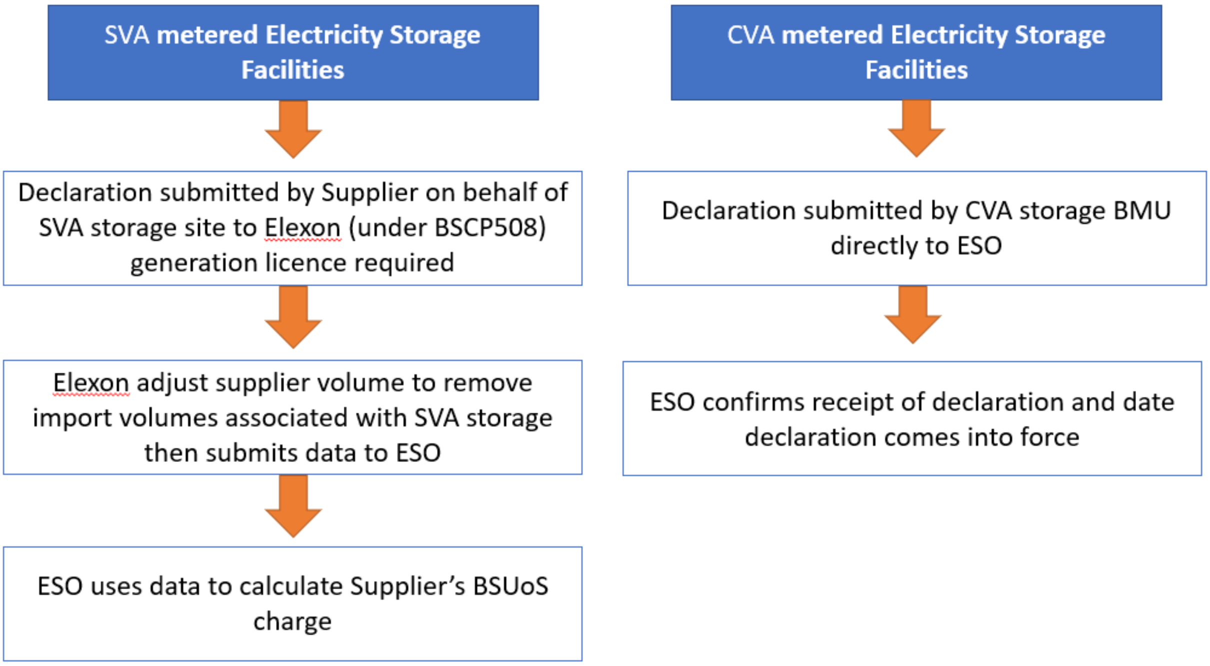
5.6.1.3 The proposal of the workgroup was that SVA Non-Final Demand sites should be declared via the supplier and the data extracted by Elexon either via a supplier declaration or by mapping the DNO line loss factor classes to metering systems to remove Non-Final Demand volumes from supplier BMUs that are then used by the ESO to bill BSUoS.

5.6.1.4 On CVA the ESO receives metered data by BMU level but cannot currently identify which BMUs are Final Demand and which aren't. A Declaration process for CVA has been created in CUSC Section 11 for TNUoS demand residual billing and may be utilised for BSUoS billing as well.

5.6.2 Obligations for Declarations

5.6.2.1 Declarations to exempt eligible sites from network charges are an existing concept.
The below graphs shows an overview of the storage declarations to be introduced on the 1st of April 2021 to implement CMP281 & P383.

This process is introduced as part of CMP281 & the equivalent BSC mod P383 (go live April 2021)



5.6.2.2 The CUSC definition of Declaration extends to Electricity Generation Facilities and Eligible Services Facilities. A template for these types of sites is yet to be completed.

5.6.3 Obtaining Settlement Data from BSC and associated modification

5.6.3.1 The workgroup agreed that to exclude eligible Final Demand sites' metered volumes from supplier BMU volume a BSC modification is required to introduce new processes that allow Elexon to identify, aggregate and exclude applicable metered volumes from BSUoS billing. A BSC modification has been raised by the ESO to create and implement these required processes in time for the 1st of April 2023. The workgroup was satisfied that this addresses the outstanding data clarifications.

5.6.4 Validation and Performance Assurance (Distribution)

5.6.4.1 The workgroup sought guidance on how performance assurance worked in the distribution world. It was highlight that BSC change P402 'Enabling reform of residual network charging as directed by the Targeted Charging Review' is currently with the Authority for decision. The BSC Panel has recommended the approval of the P402 Alternative Modification, which will require distributors to send monthly billing reports and an annual tariff setting report direct to the ESO, and therefore does not rely on Elexon, BSC Systems or agents (Elexon will provide support in the identification of CVA Registrants).

5.6.4.2 The monthly billing report will contain a daily count of Final Demand Sites and unmetered supplies (UMS) consumption, whilst the annual tariff setting report will contain 12 months actual metered consumption data only. For the avoidance of doubt, the monthly billing report will not contain metered consumption data. All data will be reported by charging band: one domestic; sixteen non-domestic (eight LV (four where a maximum import capacity is used and four where not), four HV and four EHV); and one UMS.

5.6.4.3 The ESO will therefore only receive data for Final Demand Sites and UMS that will be eligible for a residual charge, and as import consumption is only needed to invoice UMS (as it will be recovered on a p/kWh basis), metered consumption for a Final Demand Site is only needed on an annual basis for TNUoS to allocate the residual to charging bands.

5.6.4.4 Other than the creation of new LLFCs, there is no change to industry processes and therefore systems for the purpose of DUoS billing. P402 will require system changes to facilitate the new industry process to provide the ESO with the billing report and tariff setting data.

6.0 Workgroup Alternatives

6.1 Workgroup Alternative - Engie

6.1.1 During the consultation process, 1 alternative proposal was raised by Engie. Engie highlighted that "BSUoS is in principle a cost recovery charge as such the recovery of the charge should not directly influence the actions of the parties over whom the charge is recovered the current methodology recovers the total cost (£) charge over half hour periods and is converted to a MWh charge by dividing by the demand. This leads to a higher (£/MWh) charge during lower demand periods this has the effect of reducing demand further due to high BSUoS".

6.1.2 Engie further highlighted that section 2.6 of this report provides further details of the intraday effect of the current arrangements. The proposer of the alternative states that "the original proposal without this modification would have the unintended consequence of doubling this effect and potentially leads to an increase in BSUoS as the System Operator seeks to mitigate the effect of lower demand periods on system stability and security.

6.1.3 As such, Engie raised an alternative that is identical to the original proposal, however this alternative would charge BSUoS at a flat daily rate (£/MWh) as opposed to the current half hour rate on a midnight to midnight basis. Under this alternative, the same daily amount would be recovered from demand but at a flat daily rate.

6.1.4 The proposer highlighted the potential issues in their perception to the working group. The working group considered the alternative to have merit, based on an unintended consequence to overnight storage.

6.1.5 Following the raising of modification CMP361, it was decided that the outcome sought by this alternative would be covered under this workstream, and as such the proposer of this alternative withdrew support following discussion within the Workgroup.

Draft legal text

The draft legal text for this change can be found in Annex 3.

What is the impact of this change?

Proposer's assessment against Code Objectives

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;	**Positive** Better aligning the GB market arrangements and the charges faced by GB generation with those prevalent in other interconnected countries, where generation is typically not subject to such charges, allows GB and continental generation to compete on a more equitable basis and removes the potential for BSUoS to distort cross border trade.
(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);	**Neutral** However, note a beneficial effect in cost allocation: total BSUoS charges will still recover the same underlying costs, but will do so in a way that does not distort competition, by better taking account of cost recovery practice in relation to these costs in the rest of Europe (where generators do not pay), thus ensuring that generation in GB has a comparable cost base in this respect, to that in the EU.
(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;	**Positive** The growth in interconnectors, which are licensed, is a strong driver of the need to update the arrangements. Interconnectors are treated as transmission for the purpose of the Third Package; an interconnector licence can thus be viewed as a form of transmission licence.
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	**Positive** Whilst the EU Third Package arrangements recognise that different types of market organisation will exist within the wider internal market in electricity, they also acknowledge the need to reduce market distortions to deliver the full benefits of a competitive internal market in electricity.

	This change is critical in the context of GB interconnection growth which is set to significantly increase (4GW today, 8GW by 2021 and, with Ofgem's approved pipeline, potentially up to 18GW by early 2020s) which represents almost a third of GB peak demand..
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	**Neutral** This change will simplify the charging and billing arrangements, thus simplifying administration. In the short term there should be no adverse effects for GB end consumers, subject to implementation taking account of existing contractual commitments. In the longer term, aligning the GB market arrangements with our European trading partners and other interconnected countries, will better facilitate an efficient functioning internal market in electricity. GB consumers will then benefit from more competitive arrangements delivered through a wider fully-functioning competitive market in generation.
*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).	

When will this change take place?

Implementation date
1st April 2023

Date decision required by
As soon as possible after the Final Modification Report is submitted

Implementation approach

In alignment with the Second Balancing Services Charges Task Force Deliverable 1 recommendation it is proposed that CMP308 is implemented with an effective date of 1st April 2023.

Standard Workgroup consultation question: Do you support the implementation approach?

Interactions

☐Grid Code ☐BSC ☐STC ☐SQSS

☐European Network Codes	☐ EBGL Article 18 T&Cs[25]	☐Other modifications	☐Other

How to respond

Standard Workgroup consultation questions

1. Do you believe that CMP308 Original proposal better facilitates the Applicable Objectives?
2. Do you support the proposed implementation approach?
3. Do you have any other comments?
4. Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider?

Specific Workgroup consultation questions

5. Please provide your thoughts on the Workgroup's discussions post reconvening after the outcome of the Second Balancing Services Charges Task Force. Is there anything else that the Workgroup may need to consider?
6. What are your thoughts on the workgroup's discussions in regards to final demand data? Do you think the suggested solutions are appropriate? Please provide your rationale.
7. What are your thoughts on the draft legal text outlined in Annex 3? Please provide any comments you may have.

The Workgroup is seeking the views of CUSC Users and other interested parties in relation to the issues noted in this document and specifically in response to the questions above.
Please send your response to cusc.team@nationalgrideso.com using the response pro-forma which can be found on the CMP308 modification page.

In accordance with Governance Rules if you wish to raise a Workgroup Consultation Alternative Request please fill in the form which you can find at the above link.

If you wish to submit a confidential response, mark the relevant box on your consultation proforma. Confidential responses will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the Panel, Workgroup or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

[25] 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 European Electricity Balancing Guideline (EBGL – 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.

Acronyms, key terms and reference material

Acronym / key term	Meaning
BSC	Balancing and Settlement Code
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
EBGL	Electricity Balancing Guideline
STC	System Operator Transmission Owner Code
SQSS	Security and Quality of Supply Standards
T&Cs	Terms and Conditions
BSUoS	Balancing Services Use of System Charges

Reference material

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Annexes

Annex	Information
Annex 1	Proposal form
Annex 2	Terms of reference
Annex 3	Draft Legal Text
Annex 4	First Workgroup Consultation Responses
Annex 5	CMP333 and CMP308 Analysis – Workgroup Member