Decision

CMP308 – Decision and final impact assessment

Publication date:	25 April 2022	**Contact:**	Ruben Pereira, Policy Manager
		Team:	Electricity Network Charging
		Tel:	020 7901 7000
		Email:	ElectricityNetworkCharging@ofgem.gov.uk

We are publishing our decision on Connection and Use of Systems Code (CUSC) modification proposal 308 (CMP308) which will change the way that the Balancing Services Use of System (BSUoS) charges are collected from electricity network users. In 2020, the second BSUoS Task Force[1] recommended that BSUoS charges be recovered only from Final Demand[2]. This modification implements that recommendation. We consulted on our minded-to decision and received feedback from a wide range of stakeholders. Those views were taken into consideration in our Decision and Impact Assessment. The non-confidential responses we received are published alongside this document.

[1] second-balancing-services-charges-task-force-final-report.pdf (chargingfutures.com)
[2] Final Demand is defined as "electricity which is consumed other than for the purposes of generation or export onto the electricity network".

Any enquiries related to the text of this publication should be sent to Ofgem at:
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Executive summary

In November 2019, we published our Decision on the Targeted Charging Review (TCR) Significant Code Review.[3] The TCR aimed to ensure the costs of operating, maintaining and upgrading the electricity grid would be spread more fairly across users, with fewer distortions. The TCR included a review of how residual network charges[4] are set and recovered, and also sought to remove some remaining distortions in network charging, known as Embedded Benefits.[5]

Balancing Services Use of System ('BSUoS') charges are the means by which the Electricity System Operator ('ESO') recovers costs associated with balancing the electricity transmission system. Currently, these charges are recovered using a charge that varies for each half hour, and GB is relatively unusual compared to other countries in Europe in that these charges are recovered broadly equally from demand and generation. The TCR removed an Embedded Benefit associated with BSUoS[6] and noted that the differences in arrangements between Small Distributed Generators[7] and Large Generators amounted to a distortion, but did not make changes to BSUoS itself. Instead, the TCR launched two industry Task Forces to look at the costs recovered by BSUoS, who should be liable for the charges, and how these charges should be recovered.

The Task Forces made various recommendations as to how BSUoS charges should be set and recovered, including a recommendation that BSUoS costs be recovered solely from Final Demand. CMP308 is the modification that implements this change.[8] The Task Force also recommended that BSUoS charges take the form of a flat volumetric charge, set in advance. Other CUSC modifications, CMP361 and CMP362, which are with us for a decision, are proposing to implement changes to introduce an ex ante fixed BSUoS tariff.[9]

Our consultants' modelling suggests the proposed changes would reduce costs to electricity consumers. This benefit is valued at £320m in the period to 2040, assuming a Net Zero[10] compliant scenario.[11] By reducing distortions in the generation sector, CMP308 would also see GB energy system costs (excluding non-priced carbon impacts) reduced by around £400m as a result of more efficient dispatch and investment. Our modelling suggests that flows on interconnectors, which do not currently face BSUoS

[3] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment
[4] Ongoing network charges include forward-looking charges that are designed to send signals to encourage efficient use of the networks, and residual charges that are designed to ensure the networks' allowed revenues are recovered.
[5] Embedded Benefits is the name given to the differences in charging arrangements between Small Distributed Generators and large generators (with capacity >100MW) connected to either the distribution or transmission networks.
[6] This was implemented via CMP333 '*Connection and Use of System Code (CUSC) CMP333: BSUoS – charging Supplier Users on gross demand (TCR)'* which Ofgem approved on 3 December 2020: cmp333_final_version_031220 (1).pdf
[7] Small distribution connected generators with capacity less than 100MW are currently treated differently from Large generators, whether connected to the transmission or distribution networks.
[8] CMP308: Removal of BSUoS charges from Generation | National Grid ESO
[9] CMP361 & CMP362: 'BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates' | National Grid ESO
[10] In June 2019 the UK government set into law the requirement to end its contribution to global warming by 2050, bringing all greenhouse gas emissions to Net Zero.
[11] Under the non-Net Zero compliant scenario of Steady Progression, the consumer benefits are valued at £370m.

charges, would change as a result of this proposed change, and that there will be significant differences to GB generation investments. When emissions reductions in other territories are considered, overall power sector CO_2[12] emissions are expected to fall. Those from the GB energy system would go up, but emissions would fall by a greater amount in interconnected markets. We estimate that when considering the net impact of these carbon emissions, our modelling for our core scenario leads to benefits to society in the order of £810m in the period out to 2040. However, we note that when counting GB emissions changes alone using BEIS carbon appraisal values, there is an incremental £1.1bn cost to the UK economy.

Major changes to our energy system are required to deliver the Net Zero transition, with efficient investment needed in generation. We consider that well-functioning markets free from distortions are vital for the investment and flexibility needed to facilitate Net Zero at least cost, and that this proposal is likely to improve price signals and ensure cost recovery happens on a more efficient basis.

Based on our assessment, we are approving the CMP308 Original Proposal, which moves liability for BSUoS charges fully onto Final Demand. This modification will be implemented with effect from 1 April 2023. We consider the Original Proposal will better facilitate the achievement of the Applicable CUSC Charging Objectives (ACOs) and is consistent with our principal objective and statutory duties.

[12] CO_2 (Carbon Dioxide) emissions are a by-product of fossil fuel combustion and are the principal greenhouse gas contributing to climate change.

1. Background

Section summary

We describe the background to this proposal, including the existing BSUoS charges and their impact on the market, the TCR, the BSUoS Task Forces and previous modifications in this area.

BSUoS Charging

1.1. BSUoS charges are the means by which the ESO recovers costs associated with balancing the electricity transmission system. They recover several categories of costs,[13] including:

- the costs of constraints;
- the costs of frequency response services;
- the costs of reserve provision;
- the costs associated with Balancing Mechanism actions; and
- the ESO's internal costs.

1.2. BSUoS charges are currently recovered using a volumetric charge (£/MWh) from both demand customers and liable generators based on the amount of energy imported from or exported onto the network within each half-hour period.

1.3. Generators liable for BSUoS are those connected to the transmission system, and distributed generation with capacity of 100MW or greater, otherwise known as 'Large Distributed Generation' or 'Large DG'. Such generators are collectively referred to as 'Large Generators' in this document. Charges are levied on Large Generators based on their energy exports and imports, while transmission-connected and large[14] distribution-connected storage users pay BSUoS charges only on their exports. Charges are levied on suppliers in relation to their gross energy imports. Interconnector and smaller distributed (<100MW) generators and storage do not face the charge.[15]

[13] Balancing Services Use of System (BSUoS) charges | National Grid ESO
[14] 100MW and above.
[15] Storage users may pay toward the generation share of BSUoS charges through their purchases of wholesale of electricity, for which the generator may be liable for BSUoS charges.

1.4. The potential for broad reform to BSUoS charges has long been discussed, in particular due to the differential treatment between Large Generators and other generation. In addition, BSUoS has been recognised as providing signals to users that do not encourage efficient responses and may in some cases, send counter-intuitive signals.

The BSUoS Task Force

1.5. In November 2019, we published our Decision (and associated Directions) on the Targeted Charging Review (TCR) Significant Code Review.[16] The TCR included a review of how residual and cost-recovery network charges are set and recovered, in particular establishing non-cost-reflective charges should be recovered from Final Demand in a non-distortive manner.[17] Our work on TCR removed some distortions, including the removal of an Embedded Benefit[18] associated with BSUoS, but stopped short of making changes to BSUoS itself. Our November 2018 TCR minded-to decision[19] launched the first BSUoS Task Force,[20] which was asked to examine whether and how the cost reflectivity of BSUoS could be improved to provide better forward-looking signals.

1.6. The first Task Force concluded BSUoS "does not currently provide any useful forward-looking signal" and that it should be treated as a cost-recovery charge.[21] When we published our TCR Decision, we acknowledged the conclusion of the first Task Force, and asked the ESO to launch a further industry working group[22] (the second BSUoS Task Force) to assess who should be liable for BSUoS charges and how these charges should be recovered.

1.7. This second Task Force recommended[23] that BSUoS be paid solely by Final Demand, and also that it should be levied in the form of a flat volumetric £/MWh charge that was known to users in advance and was of a fixed level, not varying throughout the charging year. [24]

[16] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment
[17] The TCR aimed to ensure that residual charges are recovered from network users in a way that balanced the need to reduce harmful distortions, maintain fairness, and charge in a way that is practical and proportionate.
[18] Our TCR Decision directed that the ability for suppliers to reduce their liability for BSUoS charges by contracting with distributed generators with capacity less than 100 MW should be removed. This was achieved by recovering BSUoS charges for demand on a gross consumption basis, rather than a net consumption basis at the point the transmission network meets the distribution network. The modification that enacted this change, CMP333, was approved by Ofgem in December 2020 and implemented in April 2021.
[19] https://www.ofgem.gov.uk/sites/default/files/docs/2018/11/targeted_charging_review_minded_to_decision_and_draft_impact_assessment.pdf
[20] Review of balancing services charges (ofgem.gov.uk)
[21] ESO Word Template - Full Width (chargingfutures.com)
[22] Launch of a second Balancing Services Charges Taskforce (ofgem.gov.uk)
[23] second-balancing-services-charges-task-force-final-report.pdf (chargingfutures.com)
[24] Currently BSUoS charges are recovered using a £/MWh volumetric charge that varies in cost in each 30 minute settlement period to reflect the specific costs that arose in that period.

1.8. The key reasons for their conclusions that BSUoS should be paid solely by Final Demand were that:

- Levying BSUoS charges on Final Demand only would reduce distortions between Large Generators who are currently liable for BSUoS charges and interconnectors and other forms of generation, in particular Small Distributed Generators, who are not.

- Expanding the charge base to include distributed generation (in an attempt to address the existing distortion between Large Generators and other generators not liable for BSUoS charges) would create a new distortion between network-connected and on-site generation, which could be avoided[25] by charging BSUoS solely to Final Demand.

- Given BSUoS charges are cost recovery charges, it is not efficient to recover part of it via generation, because doing so means the costs are passed through into wholesale costs, which includes unnecessary risk premium and transaction costs.

1.9. CMP361 and CMP362[26] are the modification proposals with us for a decision which, if approved, would implement the remainder of the second BSUoS Task Force's findings. The Task Force found that that BSUoS charges, which are currently variable, should be set to a flat volumetric charge on an ex ante basis.[27] These modification proposals also concern the arrangements that would allow the ESO to manage the additional tasks of forecasting such a charge and managing risks and cash flows.

1.10. In December 2020, we published an open letter that supported the second Task Force's recommendations in principle, whilst recognising that quantitative analysis as to the overall impacts of the reforms would be required to inform a final decision.[28] Ofgem committed to carry out this quantitative work. In February 2021, we issued an invitation to tender and, following a competitive process, commissioned Frontier Economics and Lane Clark & Peacock (LCP) to carry out this work. We published their assessment of the impacts of recovering BSUoS charges from Final Demand alongside an open letter in July 2021, which ensured that the estimated magnitude and direction of impacts of the modification were available to the CMP308 Workgroup prior to the Code Administrator Consultation stage.[29] That

[25] It should be noted that collecting BSUoS charges wholly from Final Demand as a volume charge increases the potential benefit gained from avoiding demand BSUoS charges using on-site generation.
[26] CMP361 & CMP362 'BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates' | National Grid ESO
[27] In 2015 a modification, CMP250, was raised to fix BSUoS charges into a flat volumetric charge. We rejected CMP250 in 2018, before the establishment and findings of the first and second BSUoS Task Forces, and so before the first Task Force had established BSUoS charges were cost recovery charges. At the time, we did not consider that the evidence provided in the final modification report was sufficient to allow us to determine whether the solutions presented would have had a positive or negative impact on the relevant charging ACOs, and we were not satisfied that a case had been made that the proposed changes facilitated more effective competition. Ofgem's decision is available here.
[28] Ofgem response to publication of the final report of the second Balancing Services Use of System (BSUoS) Task Force
[29] Open Letter and CMP308 Wider System and Distributional Impacts of Recovering Balancing Services Costs from Demand FINAL STC 300621 (ofgem.gov.uk)

Frontier-LCP work, alongside our assessment of the modifications against the relevant ACOs and our duties, forms the basis of this decision. A supplement to the initial work which examines the impact of new BEIS carbon values on the results of the wider system analysis was published alongside our minded-to decision in December 2021 as a subsidiary document and has been considered in our findings.[30]

CMP308

1.11. Following the second BSUoS Task Force's recommendations, we set out our expectations that industry would develop solutions to modify the relevant industry code (the Connection and Use of System Code ('CUSC'), which covers the charging provisions for BSUoS charges) in line with the Task Force recommendations through the code modification process. In this instance, it was not necessary for an industry party to raise a new code modification proposal as an existing modification, CMP308, was considered an appropriate way to give effect to the terms of the Task Force outputs with regards moving liability for BSUoS charges solely to Final Demand.

1.12. The proposer of CMP308, which was raised prior to the second Task Force's findings, looked to resolve a defect they had identified relating to differences in the costs that certain GB generators were liable for when compared to generators in EU countries. The proposer argued that these differences amounted to a distortion in the generation sector which, if corrected, would allow better competition between GB generation and their EU equivalents, with whom they compete. In their view, the removal of BSUoS charges from GB generators would better align the GB 'generation cost stack' with the costs faced by EU generators and would deliver more effective competition. This, in turn, would benefit end consumers, by ensuring generation dispatch and investment in new generation is more efficient than under the *status quo* arrangements.[31] By transferring the proportion of BSUoS charges currently paid by generation to demand users, CMP308 delivers a key recommendation of the second Balancing Services Charges Task Force that BSUoS charges should be paid by Final Demand.[32]

Previous similar proposals

1.13. In 2011, a CUSC modification, CMP201,[33] was raised which sought to move BSUoS charges wholly onto Final Demand. We rejected this proposal in 2014, whilst noting that "we support the fundamental economic principle that increasing competition should lead to lower wholesale prices in the long run". In our reasons for rejection, we stated that we were "concerned that at this time the potential benefits […]

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[30] LCP modelling - BSUoS wider system modelling with updated Carbon Appraisal Values for Ofgem
[31] More efficient investment might mean the most efficient plant in the optimal location being built, or the least competitive plant closing first. More efficient dispatch should see the lowest cost generation running before other plant a greater proportion of the time.
[32] The proposer was primarily motivated to raise CMP308 to address perceived competition distortions between GB generation and its EU counterparts. The second Task Force had further reasons to support charging to Final Demand beyond this issue, as set out above.
[33] CMP201- Removal of BSUoS Charges from Generators | National Grid ESO

would not be material enough to offset the potential costs to consumers from implementing the modification". We consider there to have been significant changes to the energy system since this decision, and also that the more recent analysis that we commissioned to inform our decision on CMP308 supplants that carried out for CMP201.

Wider context

1.14. Major changes to our energy system are required to deliver the Net Zero transition, with efficient investment needed in generation. We consider that well-functioning markets free from distortions are vital for the investment and flexibility needed to facilitate Net Zero at least cost, and that this proposal is likely to improve price signals and ensure cost recovery happens on a more efficient basis. Other key work aligned to these goals includes our Access and Forward Looking Charges SCR[34] and our ongoing work on Full Chain Flexibility,[35] which builds on the existing work that we set out with BEIS in the 2021 Smart Systems and Flexibility Plan[36] and its preceding work.[37]

1.15. Key to delivering flexibility and efficient investment is ensuring that network users are in a position to respond to appropriate price signals, and that the most efficient or cost-effective providers of power or system services are used at any given time. Efficient generation dispatch occurs when the least expensive generation is brought online before more expensive generation. This concept is known as the "merit order" and is fundamental in competitive generation markets.

Price signals that are currently sent to generators through BSUoS charges are not cost-reflective and may lead to generation being dispatched "out of merit", where more expensive generation is brought into the market before less expensive generation. An example of this might be where one generator appears cheaper due to differences in BSUoS charges paid versus another source of generation. Reducing distortions to efficient price signals is therefore in the interest of consumers, as it removes barriers to competition and brings the lowest cost generators into the market first. The efficient dispatch of generation also has the potential to reduce wholesale costs, and through improvements to market functioning, has the potential to reduce the lifetime cost of generation investment across all technologies. Together, where achieved, these effects are likely to deliver lower costs for consumers.

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[34] In December 2018, we launched a Significant Code Review (SCR) into electricity network access and forward-looking charging. The objective of the SCR is to ensure that electricity networks are used efficiently and flexibly, reflecting users' needs and allowing consumers to benefit from new technologies and services while avoiding unnecessary costs on energy bills in general. Our most recent publication on this SCR consulted on minded-to positions across a number of Access subject areas https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
[35] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/full-chain-flexibility
[36] https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021
[37] https://www.gov.uk/government/publications/upgrading-our-energy-system-smart-systems-and-flexibility-plan

2. This Decision

Section summary

We describe the decision we are taking, the preceding consultation processes, and the legal and regulatory framework that underpins this work. We also provide a summary of our minded-to decision and draft impact assessment.

What are we deciding?

2.1. Our December 2021 consultation called for views on a range of questions on our proposed implementation of CMP308. The consultation questions focused on the following assessment areas:

- Assessment against Applicable Code Objectives (ACOs) and our statutory duties;
- Assessments of costs and benefits, both monetised and non-monetised; and
- Distributional impacts.

2.2. Through the work of the BSUoS Task Forces,[38] and during the industry processes relating to CMP308, there were a number of consultations where stakeholders could provide their views, including the Workgroup and Code Administrator Consultations. Our consultants' report that formed the basis of our distributional impact assessment and wider systems modelling was published in July 2021, prior to the CMP308 Code Administrator Consultation. Due to the variable nature of BSUoS charges, exact assessment of the distributional impacts of the options is not possible, but we have used the distributional modelling and wider systems modelling to quantify and support our assessment of the likely effects of this modification, as well as to provide understanding of the potential impacts for a range of possible future scenarios.

2.3. Our consultation was open for 6 weeks, reflecting the earlier publication and discussion by industry of the consultants' report, but also recognising that the consultation fell over the Christmas and New Year period.

[38] second-balancing-services-charges-task-force-final-report.pdf (chargingfutures.com)

Our decision

2.4. We have considered the consultation responses, updated our estimate of BSUoS exposure relative to existing Contracts for Difference (CfD) contracts given recent volatility and reviewed our assessments against the ACOs and our statutory duties, as well as our assessments of the costs and benefits and the distributional impacts of this change. In line with our minded-to decision, our final decision is to direct that modification CMP308 be made, with an implementation date of 1 April 2023. This will move liability for BSUoS charges solely to Final Demand, and end the existing arrangements, where both suppliers and Large Generators are liable for these charges.[39]

2.5. We sought responses on a number of questions to inform our final decision. Those questions and a summary of the responses received are presented throughout this document alongside the relevant discussions.

2.6. We received a total of twenty-two responses to our consultation, including two confidential responses. Twenty respondents agreed with our minded-to decision to implement CMP308, one respondent had a neutral view on our minded-to position, and another respondent disagreed with our position. These responses will be addressed in the following chapters.

Related modifications

2.7. There are a number of other modifications that interact with this modification or are closely linked, which this decision does not cover. These are:

- P419 - *Enhanced Reporting of Demand Data to the ESO to facilitate BSUoS Reform*[40] - seeks to enable exclusion of non-Final Demand from BSUoS charges. We have published our decision to approve alongside this decision.

- CMP361/2 - *BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates*[41] - seeks to introduce an ex ante fixed volumetric BSUoS charging tariff. We are committed to assessing the impacts of the proposals raised under CMP361/2 and issuing our final decision in the coming months.

[39] For detailed information on BSUoS liability please see Balancing Services Use of System (BSUoS) charges | National Grid ESO
[40] P419 'Enhanced Reporting of Demand Data to the NETSO to facilitate BSUoS Reform' - Elexon BSC
[41] CMP361 & CMP362 'BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates' | National Grid ESO

- CMP377 - *Clarification of Section 14 BSUoS Charging Methodology*[42] – although not directly related to CMP308, this modification, among other things, clarifies BSUoS charging methodology. On 31 March 2022, we published our decision to approve this modification proposal.[43]

2.8. We note stakeholder feedback that implementation of CMP308 changes the size of the charge faced by suppliers. The existing BSUoS charge varies from period to period, so under CMP308 suppliers face the same exposure to volatility, but the size of the charge payable by suppliers will be greater. Under the status quo arrangements, suppliers face BSUoS costs in two ways. They face it directly for the demand element of BSUoS, and also face the generation element of BSUoS where they purchase power from a generator that is liable for BSUoS charges. This second element is currently built into the wholesale price by generators in their offers. Under CMP308, all BSUoS costs will be recovered from Final Demand. Our modelling indicates that the overall average cost of BSUoS impact under CMP308 is likely to be similar to the status quo arrangements. CMP361 is considered by many stakeholders to provide mitigation for the volatility and forecasting issues. In short, implementation of CMP308 alone brings additional levels of charge without the potential for reduced risk that an ex ante charge, as per CMP361, might bring for suppliers.

2.9. We recognise that market participants would have greater certainty on the regulatory position regarding recovery of BSUoS charges if we were to publish our decisions on CMP308 and CMP361 at the same time. Given that the Final Modification Report for CMP361 was published on 8th March 2022, this would have resulted in a delay to our CMP308 decision. On balance, we considered that publishing a decision on CMP308 now, ahead of the forthcoming CfD auctions, to be more important. We think that any improvement to the accuracy of these auctions in determining the lowest cost generators and other benefits associated with moving BSUoS to Final Demand has the potential to provide significant consumer benefits. We think the overall benefit of implementing CMP308 is likely to outweigh any increased supplier risks.

2.10. For the avoidance of doubt, we will assess these decisions separately, and our decision on CMP308 should not be taken as the indication of our views on CMP361. That said, we have stated our support for the second Task Force's recommendations in principle, whilst recognising that quantitative analysis as to the overall impacts of the reforms would be required to inform a final decision. In particular, we think a broad move toward reformed BSUoS charges based on cost-recovery principles is beneficial. We are committed to assessing the impacts of the proposals raised under CMP361 and issuing our final decision in the coming months.

[4242] CMP377 'Clarification of Section 14 BSUoS Charging Methodology' | National Grid ESO

[43] Connection and Use of System Code (CUSC) CMP377: Clarification of Section 14 BSUoS Charging Methodology (CMP377) | Ofgem

Our impact assessment

2.11. Where appropriate, regulatory proposals are accompanied by impact assessments (IAs) which assess and estimate the likely associated risks, costs and benefits that have an impact on business, individuals and the environment.

2.12. Section 5A[44] of the Utilities Act 2000 imposes a duty on the Authority (its 'Section 5A duty') to undertake an impact assessment in certain circumstances. In particular, that applies where it appears to the Authority that a proposal is important. A proposal is important for these purposes if its implementation would be likely to, among other things, "have a significant impact on persons engaged in commercial activities connected with the […] generation, transmission, distribution or supply of electricity." Where this applies, the Authority is obliged to carry out an impact assessment. We consider that this impact assessment, which we have carried out in line with our impact assessment guidance,[45] meets our obligations under the Utilities Act in a proportionate and transparent manner.

2.13. Our TCR Decision ("TCR IA") did not look at the impact of moving BSUoS charges from generation to demand, as this recommendation stems from the BSUoS Task Force work. This IA looks at those impacts and is informed by our consultants' modelling, which was published on our website in July 2021[46] and was supplemented with further information in November 2021 alongside our minded-to decision.[47] We refer to this modelling within this document as "our consultants' report" or "the modelling" to aid understanding, and to draw a distinction between other analysis and assessments we have carried out.

2.14. In producing the modelling, our consultants had to make a range of simplifications and assumptions. The user groups were designed to represent a reasonable spread of different levels and shapes of consumption, but they were not representative of all consumers. As a result, the charges and bill impacts estimated were illustrative to provide an indication of the expected impacts.

2.15. In light of the current high wholesale market prices, we have considered whether further assessment is needed. We have concluded that high BSUoS charges driven by the current market conditions are likely to increase the differences between the costs faced by users that pay BSUoS and those that do not, and therefore high market prices are likely to increase the distortion present in the generation market. It would therefore follow that greater benefits could be expected from addressing a larger distortion. We recognise higher BSUoS charges mean greater costs in absolute terms will fall on Final Demand if BSUoS is no longer paid by generation users, and have considered this in our reasoning.

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[44] https://www.legislation.gov.uk/ukpga/2000/27/section/5A
[45] https://www.ofgem.gov.uk/publications/impact-assessment-guidance
[46] CMP308_Wider System and Distributional Impacts of Recovering Balancing Services Costs from Demand_FINAL STC 300621 (ofgem.gov.uk)
[47] LCP modelling - BSUoS wider system modelling with updated Carbon Appraisal Values for Ofgem

We have not updated our modelling and consider it to provide an appropriate level of understanding about the impacts of this proposal.

2.16. To aid navigation and improve readability, we have integrated the IA within this decision document, as opposed to producing a separate IA document. We consider this IA to be within scope of Public Sector Equality Duties[48] and consider this to be a non-qualifying measure for the Business Impact Target.

[48] In broad terms, the duties set out in S.149 of the Equality Act 2010 require a public authority to have regard to a number of provisions that advance equality and avoid harms toward and between individuals with a range of protected characteristics. There are some overlaps between these duties and our statutory duties as set out in other legislation. The Small Business, Enterprise and Employment Act 2015 (SBEE Act 2015) creates a legal obligation on the Government to publish a Business Impact Target, and regulators are required to transparently report on the cost to business of qualifying changes to their regulatory policies and practices.

3. The modification proposal and CUSC Panel assessment

Section summary

We describe the modification proposal for CMP308. We outline the process that led to the raising of this modification and the votes of the CUSC Panel. The CUSC Panel voted in support of this modification being better than the existing provisions (baseline).

The modification proposal

3.1. CMP308 is a single proposal, with no Workgroup Alternative CUSC Modifications (WACMs), which would move BSUoS charging liability solely to Final Demand.[49]

3.2. EDF Energy raised CMP308 in 2018 aiming to address perceived distortions in the generation market brought about by differences in BSUoS charge liability between domestic Large Generators and the EU generation with which it competes.

3.3. We wrote to the CUSC Panel Chair in November 2018 suggesting work on CMP308 be discontinued until the Task Force work was complete.[50] In response, the majority of CUSC Panel preferred to continue to progress CMP308.

3.4. Following the second BSUoS Task Force conclusions, the Workgroup felt that CMP308 was an effective way to enact the Task Force recommendations that BSUoS charges be levied on Final Demand only. We understand the ESO considered combining the work on CMP308 with that of CMP361 which seeks to deliver the remainder of the Task Force recommendations. Ultimately these modifications were progressed separately on the basis that development of CMP308 was expected to be achieved in a quicker timescale that proposals under CMP361, in turn allowing for the possibility of earlier notice of change to industry.

3.5. A second Workgroup Consultation was run in April 2021 to ensure new information raised by the second BSUoS Task Force report could be commented on. Broadly, the Workgroup was supportive of the modification, and mostly supportive of the 2023 implementation timescales, though some members felt later implementation necessary.

[49] The concept of Final Demand has previously been defined in CMP334 WACM1 which we approved in November 2020.
[50] https://www.ofgem.gov.uk/sites/default/files/docs/2018/11/cmp308_letter_on_continuation_of_the_mod.pdf

3.6. The Code Administrator Consultation was carried out in August 2021, and once again the proposal received broad support. Some concerns were raised around its impacts on the price cap methodology,[51] as well as concerns that it presented the possibility of windfall gains for generators, depending on implementation timescales.

CUSC Panel recommendation

3.7. The CUSC Panel met and voted on CMP308 in September 2021, agreeing unanimously that it better facilitated the ACOs[52] than the baseline.[53] Panel members also suggested this modification would be successful in removing distortions between different types of generators and improve the efficiency of cost recovery. Panel members suggested that the change would improve cost reflectivity of price signals and accepted Ofgem's consultants' report on the benefits. Some members did suggest Ofgem should continue to monitor whether the reductions in charges for generators would be matched by corresponding falls in the wholesale price of power, such that consumers were not disadvantaged overall. Panel members also suggested this modification would be successful in removing distortions between different types of generators and improve the efficiency of cost recovery.

3.8. The ACOs are present below, and our assessment against them is detailed in full in section 4:

a) Facilitating effective competition

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) Cost-reflective charging

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

c) Taking account of the developments of transmission licensees' businesses

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[51] Please refer to Chapter 7's section "The Energy Price Cap" for details.
[52] As set out in Standard Condition C5(5) of NGESO's Transmission Licence, see: https://epr.ofgem.gov.uk//Content/Documents/Electricity%20transmission%20full%20set%20of%20consolidated%20standard%20licence%20conditions%20-%20Current%20Version.pdf
[53] The status quo arrangements under the CUSC.

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 decisions of the European Commission and/or the Agency for the Cooperation of Energy Regulators

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

3.9. The CUSC Panel votes on CMP308 against each ACO are summarised below[54].

Table 1 - CUSC Panel voting

Option	Best Option?	ACOs better facilitated				
		a)	b)	c)	d)	e)
CMP308 Original	9 Votes	9 Votes	2 Votes	1 Vote	2 Votes	6 Votes

[54] Full discussion of the nine-member CUSC Panel's views is available in the CMP308 FMR

4. Our assessment and decision reasoning

Section summary

We are approving the CMP308 Original Proposal for implementation from 1 April 2023. In our assessment, we find CMP308 to better facilitate the achievement of the Applicable CUSC Charging Objectives and be consistent with our principal objective and statutory duties. We present the Workgroup and Panel views, a summary of the views received during our consultation and our final assessment of the proposal, as well as some key impacts of CMP308.

Consultation questions asked in our minded-to decision

1. Do you agree with our assessment that CMP308 better facilitates the Applicable CUSC objectives?
2. Do you agree that charging BSUoS charges only to Final Demand reduces distortions between Large generation and other forms of generation? Please explain why.
3. Do you have any views on the impact of this proposal on Behind The Meter Generation and its competitiveness?
4. Do you have any views on our reasoning on this proposal's effect on price signals or generation dispatch?
5. Do you have any views on our reasoning on this proposal's effect on competition between different generator types?
6. Do you have views on our assessment of the decarbonisation impacts of this proposal, both in respect of emissions from GB energy system and of overall emissions?
7. Do you have views on whether and the extent to which the changes proposed in this modification have already been incorporated into supplier decisions?
8. Do you have views on the impact of this proposal on existing supply contracts, including the possibility of costs or delayed benefits to consumers stemming from windfall gains to industry parties, or double payments?
9. Do you have views on this proposal's impacts on generator and supplier risks, including on exposure to volatile charges?
10. Do you have views on the interactions between this proposal and other changes in the sector, including other BSUoS charging reform proposals?

Legal and regulatory assessment framework

4.1. We have evaluated this proposal on a holistic basis, taking into account our understanding of the potential impact on consumers, as well as different categories of market participants. The modification has been assessed against (i) the ACOs, which we set out above in section 3, and (ii) our Principal

Objective of protecting the interests of existing and future energy consumers, wherever appropriate by promoting effective competition,[55] and our other statutory duties.

Our assessment against the Applicable Code Objectives

4.2. We have considered the issues raised by the modification proposal and the Final Modification Report (FMR) dated 23 September 2021, as well as the accompanying views and discussion, the consultation responses we received, our updated estimate of CfD-related BSUoS exposure given the further volatility of market, and the stakeholder feedback from engagement we have undertaken since the minded-to decision was published. We remain of the view that the solution proposed under CMP308 better facilitates ACOs (a), (b), and (e) and has a neutral impact on ACOs (c) and (d).

4.3. Respondents to our consultation largely agreed with our assessment, though concerns were raised around CMP308 being implemented separately from CMP361, the implications for the price cap, and on the potential impacts stemming from the CfD contractual arrangements, including possible windfall gains. We will address these specific concerns in the relevant sections below.

4.4. Our reasoning for our assessment, incorporating our considerations of stakeholder feedback, for each ACO is set out below.

ACO (a) Facilitating effective competition

4.5.1. This decision has significant competition ramifications. Some examples are provided below.

[55] As set out in Section 3A of the Electricity Act 1989

Example competition effects of BSUoS charging arrangements

Due to the differences in liability for BSUoS charges between domestic Large Generators who are liable for BSUoS and other generators[56] who are not liable, there are a number of distortions present in the current arrangements. For example, where Large Generators are competing against otherwise identical generation that is not liable for BSUoS charges we would expect to see:

- Non-liable generators being able to offer cheaper wholesale power, due to the Large Generator needing to factor BSUoS charges into the wholesale price it charges. This may mean more expensive generation appears less expensive, which will distort the merit order and means the generation running may not always be the cheapest.[57] CMP308 removes this effect.

- Interconnected generators are able to offer cheaper wholesale power when compared to domestic Large Generators due to not facing BSUoS, harming cross-border competition. CMP308 removes this effect.

- Non-liable generators may be able to offer lower bids in Capacity Market (CM) or CfD auctions, which could distort auction outcomes, or could distort balancing and ancillary services markets. CMP308 will remove this effect, meaning auction outcomes will link more directly to the costs forecasted by auction participants, rather than differences in the BSUoS charging arrangements that different participants face.

- Non-liable generators are likely to face, all other things being equal, lower costs. This may mean that plant investment and closure decisions are driven partly by BSUoS arrangements.

4.5.2. Below we set out views received from the Workgroup, the CUSC Panel and respondents to our consultation on competition matters. We then set out a summary of our views on this proposal's impacts on competition.

Workgroup and Panel Views

[56] Smaller generation and generation that exports into the GB market using interconnectors do not face BSUoS charges.

[57] We think this effect may be particularly important in the case of generation self-dispatch. Dispatch of generation in the GB market happens through two routes. The predominant method is self-dispatch of power stations to meet contractual positions. In this method, generators submit advance notifications to ESO that ensure that their contractual commitments can be fulfilled, telling the ESO when they will run. Closer to the time of delivery, the ESO manages dispatch, ensuring that the system stays in balance and that constraints and other system issues can be managed. We would refer to this as ESO-led central dispatch.

4.5.3. The majority of Workgroup participants considered this proposal to better facilitate ACO (a) with the exception of one participant, who considered supplier competition could be harmed unless CMP308 was combined with the changes proposed in CMP361. This participant felt that price cap arrangements needed to reflect the changes to ensure suppliers could recover their costs, and also considered that the approach taken by CMP361 would mitigate a range of supplier risks that arise from CMP308.

4.5.4. The CUSC Panel unanimously agreed this modification would better facilitate effective competition and therefore ACO (a). Panel members agreed that the proposal would "level the playing field" for different types of generation, and in particular, address the existing difference between the charges faced by domestic Large Generators and continental generation.

Views received from our consultation respondents

4.5.5. Of those that explicitly expressed a view, all but one respondent felt this proposal was positive against ACO (a). One respondent felt it was negative against this objective, if taken as a standalone change without CMP361.

4.5.6. Respondents to our consultation generally agreed that CMP308 reduces distortions between Large Generators and other forms of generation. Most respondents agreed with the assessment put forward in our minded-to decision that significant distortions would be reduced. They also agreed the changes would have a broadly neutral impact on the competitiveness of Behind the Meter Generation (BTMG) but felt that the situation should be monitored to ensure further distortions do not arise. Two respondents suggested that other important distortions remain, with users connected at transmission level facing different connection and access arrangements.

4.5.7. We received further feedback on the supplier impact of a standalone decision on CMP308, and again received the view that changes to the price cap would be needed to ensure suppliers are not adversely impacted. One stakeholder suggested that CMP308 increases supplier risks, as generators can mitigate their BSUoS risk using revenues from the Balancing Mechanism and Ancillary Services markets, as well as having greater capability to amend contractual positions in the face of high BSUoS costs.

4.5.8. A number of respondents raised concerns about the potential for windfall gains for certain generators as a result of these changes. We are aware of provisions in existing CfD contracts that adjust for the costs related to BSUoS charges. Due to the way these contracts are written, it is possible that some continued BSUoS adjustment payments could be made to some generators for a limited period following implementation of CMP308. Most respondents agreed that it would not be appropriate for CfD generators to continue to receive BSUoS adjustment above the level of the BSUoS cost that they have incurred as this would amount to windfall gains to those generators, which would be harmful for competition. Two consultation respondents felt that any changes to

CfD contracts must continue to allow for valid BSUoS adjustments. We discuss this issue in more detail in the next chapter.

4.5.9. Respondents generally agreed with our minded-to decision assessment that the removal of BSUoS charges from generators would lead to improvements to generation dispatch, which would bring corresponding improvements to competition between generators. Most respondents felt there would be benefits to competition between generator types, though one respondent felt the benefits would not accrue equally to all types of generation and could favour CCGTs.

4.5.10. The majority of respondents felt this change would bring about positive impacts and reduce risk for generators. One respondent claimed that CMP308 would increase net risk premia. Their reasoning was that generators face lower BSUoS risk than suppliers as generators' exposure to the risk of high BSUoS charges is balanced with opportunities for constraint and ancillary service payments. Other respondents suggested any increased risk for suppliers stemming from CMP308 could be mitigated by implementing the change in conjunction with CMP361.

Our views on the impact of this proposal on ACO (a)

4.5.11. Our assessment agrees with the Workgroup, CUSC Panel, and the majority of respondents that removal of BSUoS charges from generation would address a number of identified distortions in the wholesale market, providing more effective competition between generators. In particular, CMP308 will reduce distortions to competition between Large Generators and other generation within the GB market.

4.5.12. We recognise that the continued payment of BSUoS adjustment payments to existing CfD generators after the implementation of CMP308 could lead to an adverse impact on competition between generators and could create a new distortion between different types of generator, i.e. those who do receive the adjustments and those that do not. We agree it is important to draw a distinction between potential windfall gains and continued payments that appropriately adjust for variations in costs[58]. We also think it is important to consider separately immediate and longer term impacts. While it is possible there may be some consumer detriment from the continued payment of BSUoS adjustment payments to existing CfD generators, this is expected to be a one-off or short term impact. This can be contrasted with the longer term expected benefits that would be produced from improved competition, with charging arrangements driving enduring effects on user behaviour, such as dispatch and investment.[59] We have engaged with the Low Carbon

[58] That is to say, we draw a distinction between undue payments to users for costs they have not incurred, rather than payments associated the lagged 'True Up' process of BSUoS payment adjustment. Please see section "Contracts for Difference" in Chapter 5 for detailed explanations.
[59] Recent high BSUoS charges costs may mean that these adjustment payments are higher than would otherwise be

Contracts Company (the counterparty to the CfD contracts) and BEIS on this issue and understand that the probability of this risk bringing significant consumer impacts is low.[60] Given the low risk of consumer impacts and our expectation of consumer benefits from reduced distortions, we think the benefits of the CMP308 proposal are likely to significantly outweigh any detriment.

4.5.13. Auctions for services such as CM and CfD are an established feature of the GB market arrangements. With a large number of auctions and auction-linked investment decisions taking place over the coming decades, we expect CMP308 to bring very significant benefits, as auctions will focus more directly on the costs forecasted by participants, rather than differences in the charging arrangements that different projects may face. The potential consumer benefits of non-distortive investment in the coming years are sizable, with auctions for low-carbon support mechanisms fundamental to GB's Net Zero ambitions. The combination of better competition in auctions and better price signals in markets will increase the chance of GB investors making lower cost, efficiently sized and sited investments. Again, setting up the charging arrangements to deliver efficient investment is likely to deliver benefits far in excess of any one-off costs from the CfD contractual issues.

4.5.14. CMP308 will increase the demand side benefit available to sites with BTMG or onsite generation from offsetting demand BSUoS charges, while the share of generation BSUoS charges avoided by BTMG when compared to Large Generators will reduce. Their overall cost advantage versus Large Generators is therefore not expected to change in the round. CMP308 will lead to an increased advantage for BTMG over Small Distributed Generators and interconnectors. This is because the advantage BTMG has in offsetting demand BSUoS charges will increase, but there is not a corresponding fall in the BSUoS generation charging advantage that BTMG has over other non-liable generators.[61]

4.5.15. We consider this new BTMG distortion to be smaller than the distortion that will be addressed by the implementation of CMP308. While we consider the increase in BTMG's ability to offset demand BSUoS charges to be material and potentially distortive, we consider it to be smaller than the distortion that exists between Large Generators and all other generators at this point, due to the smaller nature of the BTMG sector.[62] We will continue to monitor this distortion.

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expected, but we consider that higher BSUoS charges increase the distortion between those that pay and those that do not pay BSUoS charges, increasing the benefits of addressing the distortions.

[60] Please see section "Contracts for Difference" in Chapter 5 for detailed explanations.

[61] CMP308 is expected to increase the size of the BSUoS charge that demand users face, which will correspondingly increases the value derived by BTMG from avoiding BSUoS charges.

[62] The amount of BTMG capacity is less than the capacity of network-connected generation. Importantly for BSUoS charging, the volumes that are supplied by BTMG are lower. Statistics from the Digest of UK Energy Statistics (DUKES) electricity suggest there is c.64GW of Transmission connected generation, c.34GW of distribution connected generation and c.11GW of autogeneration, which is how BTMG is described in that document. In terms of volumes of energy

Table 2 - CMP308 impact on different user types

GB BSUoS charge liability	Baseline		CMP308		CMP308 impact	Notes
	Demand	Generation	Demand	Generation		
Final Demand (excl. storage)	✓	×	✓	×	Pay more	Demand charge c.2x higher under CMP308. This would see demand share of balancing costs increase from c.53% to 100%.
BTMG	***Offsets***	×	***Offsets***	×	Offsets more	Offsets demand BSUoS, do not pay on generation
Smaller (sub-100MW) distribution-connected storage	×	×	×	×	No change	Storage liable for imports not related to storage operations under both baseline and CMP308. Exempt from demand BSUoS via CMP281.
Smaller (sub-100MW) distribution-connected generation	✓ **on any demand**	×	×	×	No material change	Currently pay BSUoS on any demand, do not pay on generation
Transmission-connected and Large (>100MW) distribution-connected storage	×	✓	×	×	Pay less	Storage liable for imports not related to storage operations under both baseline and CMP308
Transmission-connected and Large (>100MW) distribution-connected generation	✓ **on any demand**	✓	×	×	Pay less	Currently pay BSUoS on any demand and generation
Interconnectors	×	×[63]	×	×	No change	Exempt from demand and generation BSUoS as per CMP202

4.5.16. CMP308 is expected to increase the size of the BSUoS charge that demand users face, as demand will go from paying c.53% of the costs of balancing the system to paying 100% of the costs. Under the current arrangements, suppliers can effectively hedge a portion of the BSUoS charges through their wholesale purchases, and by buying from non-liable generation, reduce the overall

consumed, c.11TWh came from autogeneration, compared to 280TWh from the public distribution system. Therefore under 4% of electricity is currently provided by BTMG and will so will not incur BSUoS charges. Over 96% of consumed power will be from network-connected generation and so will be liable for BSUoS charges. As we state above, we still consider this difference to material, and will continue to monitor this situation, but it is smaller than the existing distortion where Large generation pay BSUoS and all other generation do not. https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes

[63] The version of this table included in the minded-to decision incorrectly suggested interconnectors pay BSUoS when acting as generation, though the notes made clear interconnectors are exempt from demand and generation BSUoS as per CMP202. This was a typographical error.

level of BSUoS their customers would need to face. We do not consider it appropriate that cost-recovery charges can be avoided through different purchasing strategies and consider it to be more consistent with supplier competition and consumers interests that all users face BSUoS charges on an equal basis. Due to the link to wholesale purchases, we recognise that sufficient notice periods are required to ensure significant levels of double payments[64] do not occur and to ensure the price cap arrangements are appropriately updated to ensure that costs can be effectively passed through. We discuss these issues in the implementation section of this document, but would note that potential BSUoS reform has been the subject of ongoing discussion with industry for a number of years, including the previous BSUoS Task Forces.

4.5.17. This proposal is closely linked to, but separate from, CMP361, which if approved would implement the remainder of the BSUoS Task Force conclusions. If CMP361 is not subsequently approved, it is reasonable to consider that some additional risk has shifted to suppliers, as the existing variable BSUoS charges will be recovered solely from demand. Under the existing price cap arrangements, supplier BSUoS costs will be reflected, meaning for price-capped domestic contracts, the increased risk to suppliers is predominantly a cashflow risk. This is also the case for their supply to (predominantly non-domestic) users on pass-through contracts. The revenue risk to suppliers relates to domestic fixed-term contracts (i.e. those that are not covered by the price cap) and to those non-domestic contracts that are not subject to pass-through arrangements.

4.5.18. We do recognise that, given the current market situation, there are a range of significant cashflow risks to suppliers, and we will consider these, and other important issues, carefully when considering BSUoS charging price cap arrangements. We understand from consultation respondent feedback that CMP361 is considered by industry to provide mitigation for increased risk exposure that stems from BSUoS charges falling on Final Demand. As noted above, we are committed to assessing the impacts of the proposals raised under CMP361 and aim to issue our final decision in the coming months.

4.5.19. Overall, we consider that CMP308 better facilitates ACO (a), because it would take positive steps toward a more level playing field between different sources of generation, and, in doing so, allow more effective competition in the generation market. We also consider it would take positive steps toward a more level playing field between suppliers.

[64] Because suppliers can buy power on the forward markets a number of years ahead, it is possible that some energy purchases will include BSUoS costs for a period where Final Demand are picking up all BSUoS costs, amounting to a double payment as BSUoS is paid directly and built into the wholesale component of a contract. We consider it likely that generators priced in potential changes to BSUoS in advance of this decision and consider the potential for double payments to be low. Where they do occur, they will reflect a windfall loss to users and/or suppliers, and a windfall gain for generators.

ACO (b) Cost-reflective charging

Workgroup and Panel Views

4.5.20. We note that most Workgroup participants considered the modification to be neutral against ACO (b). One participant felt it had a negative impact, as they considered the proposal would increase the size of the non-cost reflective signals paid by demand. They suggested the increase in the size of the demand BSUoS charge, which currently is a volatile, variable charge, could increase the non-cost reflective signals to change behaviour, for example incentivising users to reduce demand in zones with high costs driven by excess generation, where the opposite incentive would be desirable.

4.5.21. This participant noted the concerns they raised would be mitigated in the event CMP361 was approved, as an averaged, more uniform volumetric charge (as proposed by CMP361) would reduce the strength of these signals. Other participants agreed a more effective improvement to cost reflectivity would be achieved if CMP361 was also approved.

4.5.22. Two Panel members felt this modification better facilitated ACO (b). One member noted that modification could remove "noise" from the wholesale market, and so improve "visibility of genuinely cost-reflective signals".

Views received from our consultation respondents

Respondents generally agreed with our minded-to decision assessment that there would be improvements to generation dispatch if distortive cost signals that impact market prices were removed from generation. However, one respondent felt that CMP308, when taken in isolation, had the potential to increase distortive responses from demand at times of high BSUoS charges.

Our view

4.5.23. Our view remains that removing BSUoS charges from Large Generators is, in the round, somewhat better for cost-reflectivity. Removing BSUoS charges for those generators removes a non-cost reflective charge, and so therefore should leave more cost-reflective signals. All things being equal, non-cost reflective charges obscuring or altering a cost reflective signal would lead to less efficient economic outcomes, as market participants will receive poorer information about the impact of their activities and so will not properly internalise the cost of their behaviour.

4.5.24. A key example of this would be in BSUoS charges affecting generation dispatch. Dispatch should be led by efficient signals, and the inclusion of BSUoS charges in some generators' offers may alter which generators self-dispatch at a given time. This may mean the generation running may not always be the most cost-effective or efficient. We consider that CMP308 would be positive for cost reflectivity, as dispatch signals will no longer be affected by some generators having liability for BSUoS charges, and not others.

4.5.25. We recognise that like all charges, the cost of BSUoS charges may drive marginal decisions by demand side network users. These may be inefficient decisions, such as changing system use to avoid BSUoS charges in times of high prices, which was an issue noted by our consultation respondents. We acknowledged this in our response to the Second Task Force report, where we said: "[t]he current floating charge can send unhelpful signals". Where end users are incentivised to use less, this may exacerbate the network issues that are giving rise to high prices and so may form a counter-intuitive signal or perverse incentive.

4.5.26. We recognise that BSUoS charges being covered solely by Final Demand would increase this effect, but consider it is less significant than the distortion to generation dispatch as the majority of demand would not usually be expected to be price driven by real time BSUoS pricing. We do not think a move to demand-only BSUoS charges would mean the aggregate impact of these non-cost reflective signals has grown, but rather they have only grown for one set of parties but overall remained the same.

4.5.27. We also consider that in moving to demand, BSUoS charges would be moving from a more price-responsive set of users to a less price-responsive set. For many demand users, particularly domestic users and other small users who are not on pass-through contracts, the charges will not be passed through directly – they are borne by the supplier who has built their view of the expected BSUoS costs into the rates they have agreed with users. This means there will be no real signal faced by users from which a behavioural change might be driven. Of users that do have pass-through contracts, we would expect a range of price responsiveness depending on user type. For generation users, on the other hand, we would expect price responsiveness to be generally very high. It therefore follows that behavioural response to this cost recovery charge is likely to be lower if levied on demand only.

4.5.28. We recognise that the more price responsive demand users may also be those users who have, or are more likely to invest in, BTMG. While we agree with respondents that the overall level of distortion coming from this user type regarding BSUoS charges is likely to be small, we think it prudent to monitor the situation.

4.5.29. As noted above, the related modification CMP361 aims to replace the existing variable BSUoS charges with a flat volumetric charge. If approved, this would potentially mitigate some of these effects, though as a separate modification we make no judgement on that proposal within this decision. Regardless of the form of the charges, we consider that BSUoS charges being payable solely by Final Demand means they are likely to be less distortive to cost-reflective signals, given the relative responsiveness to prices of the typical generation and demand users. We remain of the view that CMP308 better facilitates ACO (b), but we do think it is a relatively minor improvement.

ACO (c) Taking account of the developments of transmission licensees' businesses

Workgroup and Panel Views

4.5.30. Five Workgroup members considered that this modification was neutral against ACO (c), and three Panel members felt this modification better facilitated ACO (c). Of the three members that felt that this modification better facilitated ACO (c), one provided reasoning, noting that "as interconnection capacity increases, the current market distortion between GB and continental generators will increase. CMP308 takes account of this development and will prevent the existing distortion from becoming exacerbated". A number of Code Administrator Consultation responses focused on the theme of growth in interconnection, suggesting that CMP308 might prevent a perceived worsening of existing distortions between interconnected and GB markets that such growth might bring. Of the CUSC Panel members who supported this Objective,[65] one directly addressed this point, noting "the effect of the market distortion between GB and continental generators will increase unless [CMP]308 is passed".

Views received from our consultation respondents

4.5.31. A small number of respondents explicitly felt that CMP308 had a positive impact on this Objective. Of those that gave their rationale, one felt that CMP308 will allow increased harmonisation and competitiveness of UK & EU generators. Another felt, in leading to potential improvements to the level playing field between distribution-connected and interconnected generation with transmission-connected generators, CMP308 would reflect the increasing importance of these other generation types.

Our view

4.5.32. We have considered whether this change reflects necessary changes in the transmission licensees' businesses. The last significant changes to the arrangements around which generators were liable for BSUoS charges took place in 2012, when BSUoS charges were removed from interconnectors.[66] Our 2019 TCR Decision removed an Embedded Benefit associated with BSUoS charges but did not address the difference in liability between Large Generators and other generation.

[65] Three "Vote 1" panel member voting statements supported the view that this objective was better facilitated, though only one listed objective c) as being better facilitated in the "Vote 2" table within the FMR.
[66] Demand BSUoS charges were removed from interconnector BMUs under CMP202, raised by NGET. https://www.ofgem.gov.uk/sites/default/files/docs/2012/08/cmp202-decision-letter_0.pdf

4.5.33. The level of distributed generation is expected to increase from c.28% to c.33% of capacity by 2030 according to the ESO's Future Energy Scenarios (FES)[67] 2020 Consumer Transformation scenario, and interconnector capacity is expected to increase from c.5GW to c.19GW by 2030 under the FES 2021 Consumer Transformation scenario. Our consultants' modelling shows that the BSUoS charging treatment has significant impacts on the interconnector flows and on the competitive relationship between different generation types.

4.5.34. This modification removes BSUoS charges from Large Generators, bringing arrangements in line with those for interconnectors and Smaller Distributed Generators. This is important, given the increasing contribution of interconnectors and Smaller Distributed Generators.

4.5.35. As we set out in our minded-to decision, this modification is important in light of changes to the market, but we ultimately consider these arguments to relate to competition benefits, and think that the focus on competition in the consultation responses on this ACO supports this position. In effect, there exists a distortion to competition and we consider that CMP308 would provide an improvement as explained under ACO (a) above. We agree a non-discriminatory regime where BSUoS charges do not fall only on certain generators is more consistent with a system where increasing amounts of generation is not transmission-connected or large distribution connected domestic generation, but this is addressed by our assessments of ACO (a).

4.5.36. Therefore, we remain of the view that this modification is, on the whole, neutral in terms of ACO (c).

ACO (d) Compliance with the Electricity Regulation and any relevant legally binding decisions of the European Commission and/or the Agency for the Cooperation of Energy Regulators

Workgroup and Panel Views

4.5.37. No Workgroup members felt this ACO was better facilitated. Three Code Administrator Consultation responses did support this, with one suggesting benefits to compliance with EU law. One Panel member also felt the change could better facilitate compliance, noting they agreed with the rationale set out in the original proposal. In broad terms, the proposal suggests that ACO (d) is better facilitated as reducing market distortions will help to deliver the full benefits of a competitive internal market, something particularly relevant in the context of interconnector growth.

[67] FES 2020 documents | National Grid ESO

Views received from our consultation respondents

4.5.38. One respondent explicitly stated this ACO was better facilitated but did not provide reasoning.

Our view

4.5.39. We believe that ACO (d) is not relevant for the modification. We consider that moving BSUoS charges only to demand does not affect compliance with the Electricity Regulation or other relevant legally binding decisions of the Commission or Agency. It is our view that the impact is neutral, a view shared by all but one Panel Member.

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

Workgroup and Panel Views

4.5.40. A number of Workgroup members suggested this ACO was better facilitated by CMP308. In particular, they felt that cost recovery from Final Demand is more efficient than from generation and storage, and so a change to reflect this fact would improve the efficiency of the charging methodology. Two other members suggested the changes would better align BSUoS charging and TNUoS charging terminology. Another member felt CMP308 would simplify the charging and billing arrangements, which would consequently simplify administration. The Code Administrator Consultation saw a number of responses supporting the modification as better facilitating objective (e), but no qualitative statements were provided. Six Panel members felt this Objective was better facilitated, with one suggesting it might better facilitate efficiency in the implementation and administration of the charging methodology.

Views received from our consultation respondents

4.5.41. The majority of respondents that stated a view felt CMP308 would better facilitate this Objective, though one respondent felt that CMP308 by itself would not simplify billing arrangements, nor were they convinced by the potential for improvements from a new billing system.

Our view

4.5.42. We agree with the majority of respondents and the Panel that simplified arrangements would have a positive impact on ACO(e) as they facilitate efficiency in the implementation and administration of the use of system charging methodology. We acknowledge one respondent’s comments that any potential efficiencies from a new ESO billing system are unproven.

Summary of our assessment against the ACOs

Table 3 - Assessment of CMP308 against the ACOs

Proposed Solution	Does the proposal better facilitate the ACO?				
	ACO (a)	ACO (b)	ACO (c)	ACO (d)	ACO (e)
Original	Yes	Yes	Neutral	Neutral	Yes

4.5.43. In summary, we agree with the CUSC Panel's recommendation that this modification better facilitates the ACOs than the baseline methodology.

Assessment against the Authority's statutory duties

4.6. Having concluded that CMP308 overall better facilitates the ACOs in our assessment above, we also assessed the approval of the Original Proposal against our statutory duties, including our Principal Objective to protect the interests of existing and future consumers and the various specific matters identified in section 3A of the Electricity Act 1989. We set out below some specific analysis of key aspects of our statutory duties.

Financial impacts on consumers

4.7. As noted above, the net consumer benefits associated with this change are expected to be c. £320m in the period to 2040, assuming a Net Zero compliant scenario.[68] Separate from this, we are aware of the potential for unmodelled costs arising from the implementation of CMP308. Specifically, we understand that, without changes to existing CfD contracts, some generators may continue to receive unwarranted compensation for BSUoS charges via BSUoS adjustment payments for a short period after the implementation date of April 2023. This could result in overcompensation of a cost that has not been incurred by CfD contract holders, at the expense of consumers.

4.8. We estimate that, should this risk fully materialise, the worst-case impact would be in the region of £400m (an estimate which takes account of recent rises BSUoS charges driven by a sustained increase in global gas and electricity prices).

4.9. At the time of this decision, following engagement with the Low Carbon Contracts Company (the counterparty to the CfD contracts) and BEIS, we understand that a group of major generators, accounting for over 85% of CfD generation capacity by full year 2024/25, have agreed with the principle that

[68] Further to this, system benefits are set out in Chapter 5. Under the non-Net Zero compliant scenario of Steady Progression, the consumer benefits are valued at £370m.

overcompensation should not take place. This would significantly reduce the worst-case impacts, meaning that the modelled benefits of CMP308 are more likely to be fully realised.

4.10. Notwithstanding the possibility of a short-term additional consumer cost associated with CMP308, which would impact on the benefits case associated with the change, we continue to consider that the overall impact of the change to be in the interest of existing and future consumers on the basis that any reduction in consumer benefits can be outweighed by the wider benefits of this reform, such as increase in system efficiency through the removal of major distortions and improvement of price signals.

4.11. Lastly, we note that whilst GB electricity system costs decrease, the cost to the GB economy associated with abatement will likely increase, due to the reasons explained in the 'Environmental matters' paragraphs below.

Environmental matters

4.12. As explained in more detail in section 5, the decarbonisation impacts of this modification are complex. Our modelling indicates that the CMP308 reform is expected to increase net emissions associated with the GB electricity system. That is to say, if GB is considered in isolation, emissions from the electricity sector will increase as a result of this modification. However, it is expected that this modification will reduce carbon emissions in interconnected markets, such as the EU and Norway, by a greater amount. As a consequence, the overall impact of the proposed change is expected to be a net reduction in emissions associated with the electricity systems of GB and interconnected countries (if considered in the round). With regards to carbon abatement costs, if we consider impacts solely on a GB basis (and not more broadly to include neighbouring countries), the cost of carbon abatement for the GB economy as a whole is likely to increase as a result of this change.

4.13. Section 3A of the Electricity Act 1989 expressly provides that consumers have an interest in the reduction of electricity-supply emissions '*wherever their source*'.[69] It is therefore appropriate to consider the impacts of this reform in interconnected countries as well as GB as part of our assessment. This is consistent with Green Book guidance[70] and recognises the global nature of climate change and greenhouse gas emissions, and the interconnected nature of power markets.

[69] Electricity Act 1989 s. 3A(1A)(a) provides that consumers have an interest in "*the reduction of electricity-supply emissions of targeted greenhouse gases*". s. 3A(5B) defines such emissions to include "*any… emissions* [of a targeted greenhouse gas] (*wherever their source) that are wholly or partly attributable to, or to commercial activities connected with, the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors*".

[70] The Green Book is the government's guidance on options appraisal and applies to all proposals that concern public spending, taxation, changes to regulations, and changes to the use of existing public assets and resources. It supports the design and appraisal of proposals that both achieve government policy objectives and deliver social value.

4.14. Overall, CMP308 is expected to result in a reduction of emissions associated with the electricity systems of GB and neighbouring countries, which we consider to be beneficial to the environment and global climate change goals and is consistent with the Government's stated policy goals which include the reduction of CO2 emissions from abroad, as well as from the UK[71]. We have considered the interactions with the UK Government's Net Zero Targets[72] (of which Ofgem has recognised itself as a key facilitator[73]), and we recognise that any increase in electricity-system emissions associated with GB will require to be offset by actions elsewhere (in the energy sector or otherwise) in order to ensure that Net Zero targets are met. In addition, the underlying purpose of such targets is to try to minimise climate change, and we consider that objective is best facilitated by actions that are likely to result in an overall reduction in greenhouse gas emissions associated with electricity supply.

Competition matters

4.15. For the reasons set out under our assessment of ACO (a) above, we have concluded that the implementation of CMP308 will promote effective competition. Removing distortions between generators of different size and connection voltage translates into more efficient competition, and this is likely to increase the ability of the market to choose the most efficient solutions, rather than being pushed towards certain investments by the charging arrangements. A market that produces efficient outcomes is in the interest of existing and future consumers.

The Price Cap

4.16. As discussed elsewhere in this document, we recognise that it is important to consider how the price cap would respond to any increase in supplier costs and ensure that costs can be effectively passed through given the potential impact on suppliers and the retail market, and the potential consequent impact on consumers. It should be noted that the price cap methodology does exist to reflect the efficient costs that suppliers incur, and for either a solo CMP308 or potential future combined CMP308 & CMP361 solution, we may review the BSUoS allowance in the price cap to reflect changes in the BSUoS methodology in the future. We discuss these issues in the implementation section in Chapter 7 of this document.

Security of supply and efficiency and economy on the networks

4.17. Under Electricity Market Reform, the Capacity Market was introduced to ensure investments are made to achieve security of supply and Contract for Differences were introduced to encourage low carbon

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[71] See, for example, page 7 of Social and Environmental Guidance to GEMA Condoc (publishing.service.gov.uk)
[72] GEMA is obliged under s.3B Electricity Act 1989 to have regard (and has had regard in relation to this decision) to Social and Environmental Guidance issued by the Secretary of State, which makes reference with regards Net Zero to the Government's obligations under the Climate Change Act 2008. Condoc (publishing.service.gov.uk)
[73] See, for example, Ofgem's strategic narrative for the period 2019-2023 Ofgem strategic narrative: 2019-23 | Ofgem and Ofgem's 2020 Decarbonisation Action Plan Ofgem's Decarbonisation Action Plan | Ofgem

generation investment. There are linkages between these mechanisms and they rely on efficient market clearing to achieve their goals at least cost. Current BSUoS charges are volatile and considered hard to predict for market participants. Removing BSUoS from generation will reduce the uncertainty associated with investment. Therefore, all else being equal, shifting BSUoS to Final Demand is likely to generate the required level of security more efficiently and may lead to more cost-effective low carbon generation investment.

4.18. Regarding efficiency and economy on the networks and as explained in our assessment of this modification against ACO(b), we think that BSUoS charges can undermine or dilute the effectiveness of useful locational and operational signals and introduce significant differences in delivered wholesale electricity prices. This modification will therefore improve price signals. We consider price signals, whether administered or market-based, to be crucial for efficient electricity system development and function. This improvement to cost reflectivity will, all other things being equal, help ensure networks are used efficiently. This reform to BSUoS ensures that it no longer provides marginal incentives to choose connections at one voltage level or at a particular size. It is therefore likely to affect dispatch decisions, which we would expect to have knock on impacts on network use and investment needs as well as markets.

Vulnerable consumers[74]

4.19. Our distributional assessment indicates that there is a low estimated financial impact on all domestic users, and as such we do not consider this policy change to have a significant impact on the specific groups of consumers outlined above.

Our overall view

4.20. Considering our Principal Objective and statutory duties in the round, in particular the above areas, we consider that implementation of CMP308 is consistent with our Principal Objective to protect the interests of existing and future consumers and our other statutory duties. We considered the expected impacts in the short, medium and long term in the context of a more efficient recovery of these costs and the reduction of potential adverse effects. Taking into account the impacts for consumers, including financial, environmental and competition aspects, as well as the impact on the price cap, security of supply and vulnerable consumers, we believe that on balance the benefits of implementing this modification overall outweigh any detriments to consumers.

[74] This includes individuals who are disabled or chronically sick, individuals of pensionable age, individuals with low incomes, and individuals residing in rural areas.

Relationship to the TCR

4.21. As noted above, the key feature of this proposal is the move from charging BSUoS, which is a non cost-reflective charge, from generation and demand solely to Final Demand. There are similarities with conclusions reached in our TCR Decision, where we decided that residual charges, as non cost-reflective charges, should be borne solely by Final Demand. We would stress that this decision is not part of the TCR SCR and is not covered by the principles of that review, though we do consider our decision to approve CMP308 to align to our wider charging strategy. We also think that BSUoS reform decisions can be thought of as part of a suite of strategic changes, reaching back to our Embedded Benefits reforms, that have aimed at ensuring that network costs of varying types are recovered without distortions to investment or operational signals.

Decision

4.22. We have considered the issues raised by the modification proposal and the Final Modification Report (FMR). We have considered and taken into account the responses to the industry consultations on the modification proposal which are attached to the FMR. We have consulted on our minded to position and considered the responses we received, as well as the views received in direct stakeholder engagement. We conclude that:

- Implementation of CMP308 will better facilitate the achievement of the ACOs than the baseline methodology; and

- Directing that the modification be made will be consistent with our Principal Objective and statutory duties;[75]

Therefore, our final decision is to direct that modification CMP308 be made.

[75] The Authority's statutory duties are wider than matters which the CUSC Panel must take into consideration and are detailed mainly in the Electricity Act 1989 as amended.

5. Assessment of Costs and Benefits

Section summary

This section considers how the costs and benefits of moving BSUoS charges to Final Demand can be quantified. It explains the method, main assumptions and results from the wider system modelling and also the challenges. It also identifies important hard-to monetise costs and benefits that are part of our assessment of the proposed modification.

Questions asked in our minded-to decision consultation

11. Do you have views on the modelled assessment of consumer and energy system benefits? Please provide quantitative analysis and any further information.
12. Is our assessment of non-monetised costs and benefits reasonable? Are there any other factors we should consider?
13. Do you consider the consumer and system benefits identified in our consultants' modelling to represent a reasonable view of the potential effects of this modification?
14. Do you consider that Ofgem has duly considered all relevant consumer and system benefits? Are there any areas which could benefit from further analysis?
15. Our modelling assumes that CfD adjustment payments designed to compensate contract holders for the BSUoS charges they face will no longer be paid in the event generation is not liable for BSUoS charges. Do you agree with this assumption, and do you have views on our assessment of the risks associated with existing CfD contracts?

System and Consumer welfare impacts

5.1. Our assessment of the impact of moving BSUoS charges to Final Demand aims to apply principles of cost-benefit analysis consistent with the HMT Green Book,[76] BEIS/HMT guidance[77] and our own guidance.[78]

5.2. To assess the quantified impacts of implementing this proposal, we commissioned Frontier Economics and Lane Clark and Peacock (LCP) to carry out analysis[79] of:

[76] The Green Book (publishing.service.gov.uk)

[77] Valuation of energy use and greenhouse gas emissions (publishing.service.gov.uk)

[78] Impact Assessment Guidance | Ofgem

[79] LCP/Frontier report - Wider System and Distributional Impacts of Recovering Balancing Services Costs From Demand

1. The costs to users (thereby quantifying consumer welfare).

2. 'Wider' system costs which refers to the impact on the wider energy system including unpriced carbon (measuring the societal impact of the reform).

3. Distributional impacts of the proposed reform (reported in section 6).

5.3. BEIS guidance[80] recommends that when a policy has a marginal impact on emissions, and some of these reductions are outside GB, to consider external impact on emissions as well as the national. Our published analysis of wider benefits (which include unpriced values for carbon) followed this principle and provided information on wider system costs on a GB only basis as well as effects outside GB.

5.4. The analytical period for the costs to users and the 'wider' system costs is between 2023 and 2040. Costs and benefits over this period are measured in real 2020 prices. Discounting is carried out at the Treasury rate of 3.5% to give Net Present Benefits, Costs or Values in 2022.

Assessment Methodology

5.5. Our consultants have used LCP's proprietary EnVision model. This is a well-established, fully integrated model of the GB power market. As described in section 2.1 of the consultants' report, it can measure the likely short-term dispatch and operational responses that could result from the proposed changes to BSUoS charges. It can also simulate long term plant investment and retirement decisions that might result from the change.

5.6. The model can provide insights into how the proposed change feeds into generation economics, the generation capacity mix, Capacity Market (CM) auctions, low carbon subsidy costs, wholesale prices and carbon dioxide emissions.

5.7. In the modelling, a comparison is made between a *status quo* counterfactual where BSUoS charges are recovered from both Large Generators and all demand based on a per unit energy charge (£/MWh) set *ex post*, and a factual where BSUoS charges is recovered from only suppliers on a variable £/MWh basis.[81] This comparison assumes all generation sources placed 'in front of the meter'[82] are on a level playing field. BTMG can be used to reduce a users' import volume by reducing the number of units taken

[80] Valuation of energy use and greenhouse gas emissions (publishing.service.gov.uk)
[81] In simple terms, the counterfactual here represents the existing arrangements as they might develop over time, while the factual scenario represents the development over time of the system if we approved CMP308.
[82] Generation "in front of the meter" is connected to one of the public electricity networks, such as the transmission or distribution networks and primarily serves to supply electricity to users on other sites using the networks. Generation sited "behind the meter" is that which primarily supplies demand situated on the same site, rather than elsewhere. Some BTMG will also export on to the network, and for that power consumed off-site will be typically treated as any other comparable generator.

from the networks on which BSUoS charges would be levied. The factual assumes BTMG would get a greater advantage from reducing BSUoS charge exposure for load due to the higher BSUoS demand charge, but also that it would not avoid the generation BSUoS charge that BTMG can avoid in the counterfactual scenario.

5.8. It is important to both use a credible 'Business as Usual' baseline and to consider uncertainty in analysis, otherwise results may be misleading or only relevant to a particular development of the energy system. Our consultants' report presents results for two credible pathways of system development described in National Grid's FES 2020 documents.[83] These are Consumer Transformation (CT) and Steady Progression (SP). These scenarios provided assumptions on market and system developments such as commodity prices, demand, low carbon build and interconnector build.

5.9. In this document we treat CT as the reference scenario, as it meets the UK's Net Zero obligations set out in the amended Climate Change Act 2008. Key elements of this scenario are that consumers are willing to make large changes in energy related behaviours, there is a high degree of heating electrification, high energy efficiency is achieved and there is considerable demand side flexibility. In contrast, SP has progress on decarbonisation but with little decarbonisation of heat and little change in consumer behaviours. The underlying mechanisms that give rise to benefits are similar for both scenarios, and for this reason, we concentrate on the detail of CT. However, similar information is available in the consultants' report for SP, with significant differences highlighted.

5.10. The annual average BSUoS charge projections under each scenario over time are illustrated below.

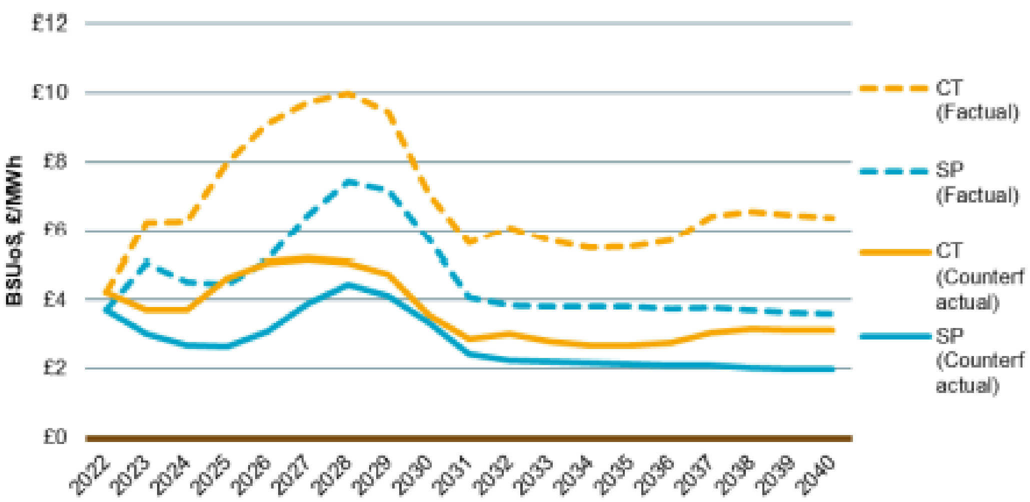


Figure 1 - Annual BSUoS Charge projections. Source: LCP/Frontier

83 FES 2020 documents | National Grid ESO

Assessment Findings

5.11. In light of the current high wholesale market prices we have considered whether further assessment is needed. We have concluded that high BSUoS charges driven by the current market conditions are likely to increase the differences between the costs faced by users that pay BSUoS and those that do not, and therefore high market prices are likely to increase the distortion present in the generation market. It therefore would follow that greater benefits could be expected from addressing a larger distortion. We have not updated our modelling and consider it to provide an appropriate level of understanding about the impacts of this proposal.

Assessment Findings

5.12. In simple terms, as BSUoS charges are currently levied in approximately equal measure on generation and demand, charges faced by demand might be expected to approximately double if placed on demand alone as a result of the proposed reform.[84] However, the generation charging base is slightly smaller than the demand base, due to the specific arrangements described earlier in this document where interconnectors and Small Distributed Generators supply demand but do not pay BSUoS charges. These characteristics are reflected in the starting position of our model. In future years, the generation charging base grows compared to the demand charging base, with more domestic generation exporting to interconnected markets.

5.13. The modelling suggests that the move to demand only paying BSUoS charges sees similar peaks and lows in average BSUoS charges across the year to the *status quo* arrangements modelled in the counterfactual option, but with demand charges typically 1.5 to 2 times higher under CMP308, reflecting the smaller charging base. This can be seen in the charts below, which we reproduce from our consultants' report. The charts[85] show the BSUoS charge projections for an average summer day in the year 2025, highlighting that during the summer, when demand is low, BSUoS charges tend to be high at night. This sends a perverse signal to users, as more demand would reduce balancing costs.

[84] Currently, BSUoS charges are levied on each MWh of generation from liable generators, and each MWh of supplier demand. Moving BSUoS only to demand means the overall number of units over which the BSUoS in total is charged approximately halves. To put it another way, the denominator of the current BSUoS calculation is all liable generation MWh and all liable demand MWh. If CMP308 is approved, the denominator will be only the liable demand MWh and the unit rate will approximately double.

[85] The report includes four graphs showing BSUoS charges for an average winter day as well as the summer charts shown above.

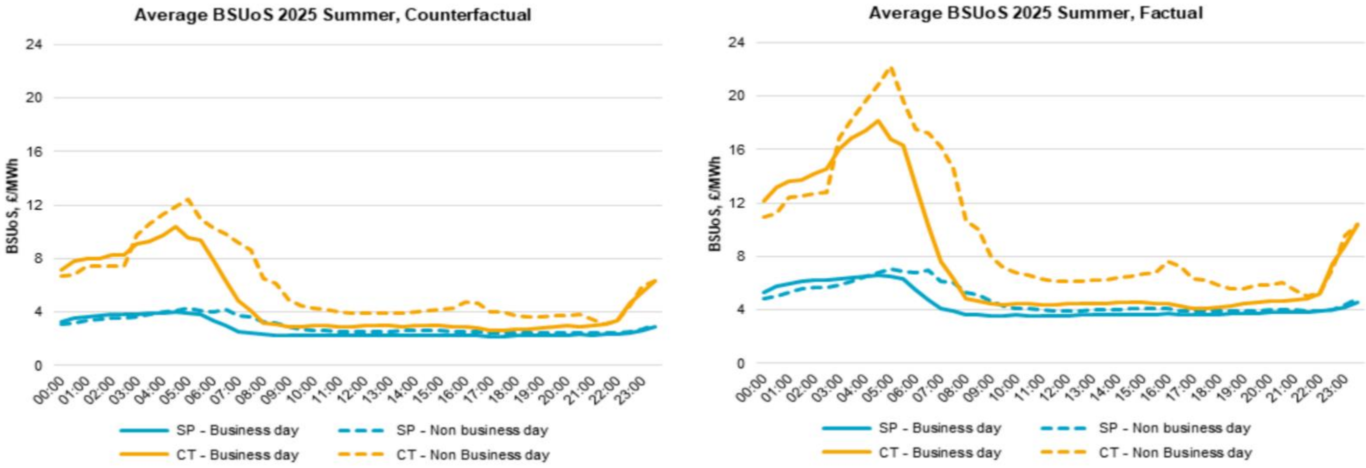


Figure 2 - BSUoS charge projections, £/MWh, Status Quo (Counterfactual) at left, CMP308 demand only BSUoS (Factual) right. Source: LCP/Frontier

Wholesale prices

5.14. GB is unusual in Europe in having material levels of charges for balancing services levied on generation, and BSUoS charges are significantly higher than balancing charges faced by generators in the countries GB is or will be interconnected to.[86] Under both CT and SP scenarios, the removal of BSUoS charges from generation leads to more generation from CCGT plants and lower output from storage and peaking plant.[87] The removal of BSUoS charges leads to wholesale price decreases in both scenarios, as generators no longer pass through these costs in their wholesale market prices.

5.15. We would expect that wholesale costs fall when BSUoS charges are removed from generators, but only in cases where the marginal – and so price-setting - generator pays BSUoS charges currently. Where a period’s marginal generator in the status quo does not pay BSUoS charges, for example if they are Smaller Distributed Generators, we would not expect the wholesale price to fall where BSUoS charges were removed from Large Generators.[88] In later years, under the CT scenario, there are fewer periods in which the marginal generator is one that is currently liable for BSUoS charges. This means fewer periods where the removal of BSUoS charges feeds through into lower wholesale prices. Under the SP scenario,

[86] As set out previously, balancing services charges are not charged to generators in France, Ireland or the Netherlands, and levels faced by generation are much lower than generators in GB in Belgium, Norway and Denmark. More information can be found in the second BSUoS Task Force report http://www.chargingfutures.com/media/1477/second-balancing-services-charges-task-force-final-report.pdf

[87] Peaking plant are typically natural gas-powered reciprocating engines or gas or oil fired open cycle gas turbines, They have lower efficiency than CCGTs, but ramp up faster and typically have lower capital costs.

[88] Put another way, when generation connected to the GB market via interconnectors or distribution networks, or supported by CfDs set the system marginal price, we would not expect to see a reduction. This is the case in the majority of periods in the counterfactual for the CT scenario in later years.

there are more periods in which a CCGT is at the margin in the counterfactual and the reduction in wholesale prices is more substantial.

5.16. Figure 3 shows the projected wholesale price difference between the *status quo* arrangements (Counterfactual) and the changes proposed in CMP308 which move BSUoS charges to demand only (Factual). These are shown for the CT scenario. The chart shows the way in which wholesale reductions become less significant as the system develops to one with more generation supported by CfDs or those which are not domestic Large Generators. More information on these dynamics can be found in our consultants' report.

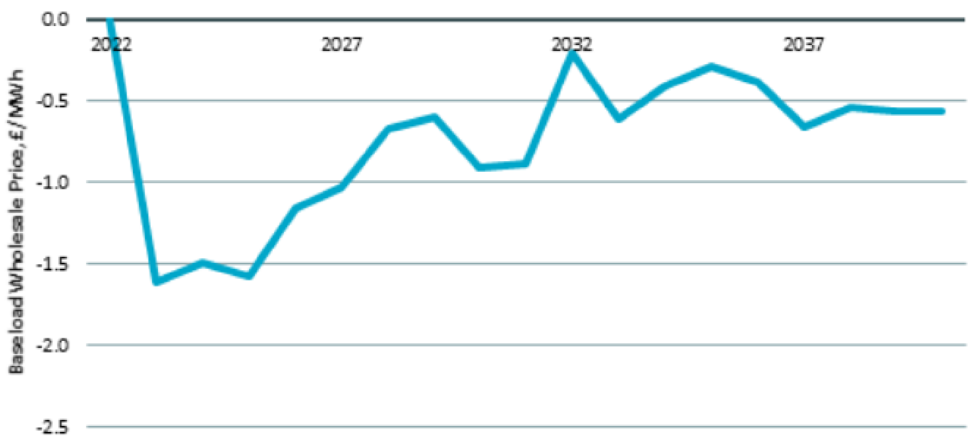


Figure 3 - Wholesale Price (Factual – Counterfactual) Consumer Transformation. Source: LCP/Frontier

Consumer Benefits

5.17. Figure 4 for the CT scenario illustrates how, through time, a move to demand only BSUoS charging leads to net consumer benefits of £320m.[89] Initially, the total impact from lower wholesale costs, lower low carbon support payments such as CfDs (where new generators are no longer building BSUoS charges into their auction bids) and lower CM payments is insufficient to outweigh additional BSUoS charges. Low carbon support payment reductions and the lowering of CM payments in future years drive the consumer savings (yellow and pink bars). As these increase over time, overall consumer costs reduce. This is due to the reform levelling the playing field for new generation capacity, leading to more efficient and cost-effective generation being built. Less distortive markets mean that the lowest cost generators are built and dispatched first, as markets and auction are not distorted by participants facing different levels of

[89] 2022-2040 NPV, 3.5% discount rate.

BSUoS charges. Under the SP scenario, the wholesale cost reductions are more significant, in some years falling by more than £2/MWh.[90]

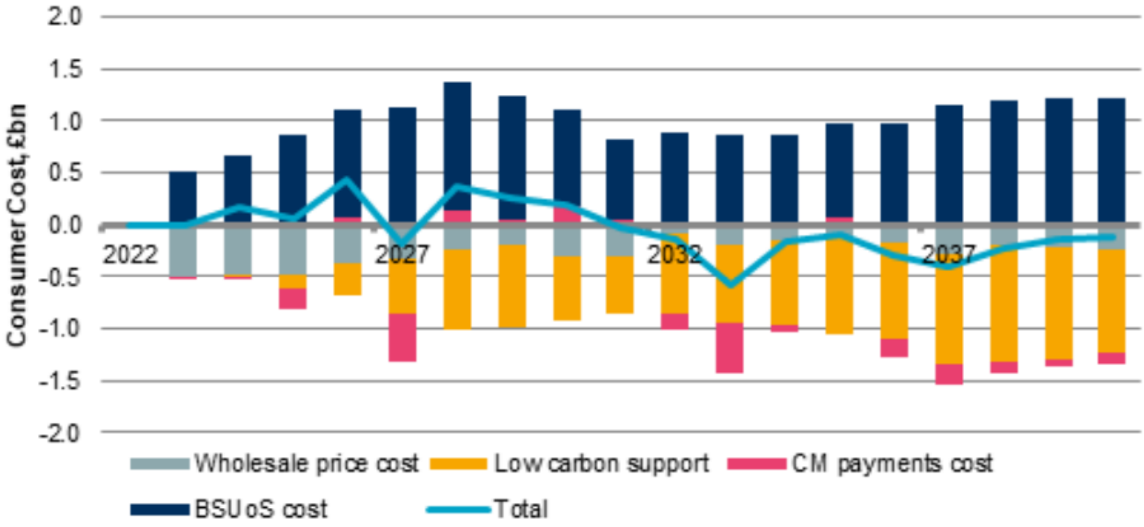


Figure 4 - Consumer Cost (Factual – Counterfactual). Source: LCP/Frontier

Capacity

5.18. The modelling suggests that under both CT and SP scenarios, CMP308 is likely to lead to an increase in the number of Large Generators, in this case transmission connected CCGTs. This comes at the expense of smaller distribution-connected gas peaking and battery storage, who do not pay BSUoS charges under the *status quo* arrangements and therefore do not benefit from the levelling of the playing field.[91]

[90] More information is available in section 2.4 of our consultants' report.
[91] See sections 2.4.1 and 2.4.2 of our consultants' report.

Figure 5 - Capacity (Factual-Counterfactual) Consumer Transformation. Source: LCP/Frontier

Generation

5.19. Under CT, new and existing CCGTs provide more volume in early years, displacing interconnected generation and distributed peaking plants. However, as this is a Net Zero consistent scenario, wholesale price decreases driven by the removal of BSUoS charges from generation cause further exports across the interconnectors with offshore and onshore wind providing the marginal source of generation. Hence, in early years interconnector imports are displaced by increases in domestic CCGT generation and in later years' exports are increased by wind becoming more competitive with interconnected markets' generation once the playing field is levelled. This can be seen in the chart below.

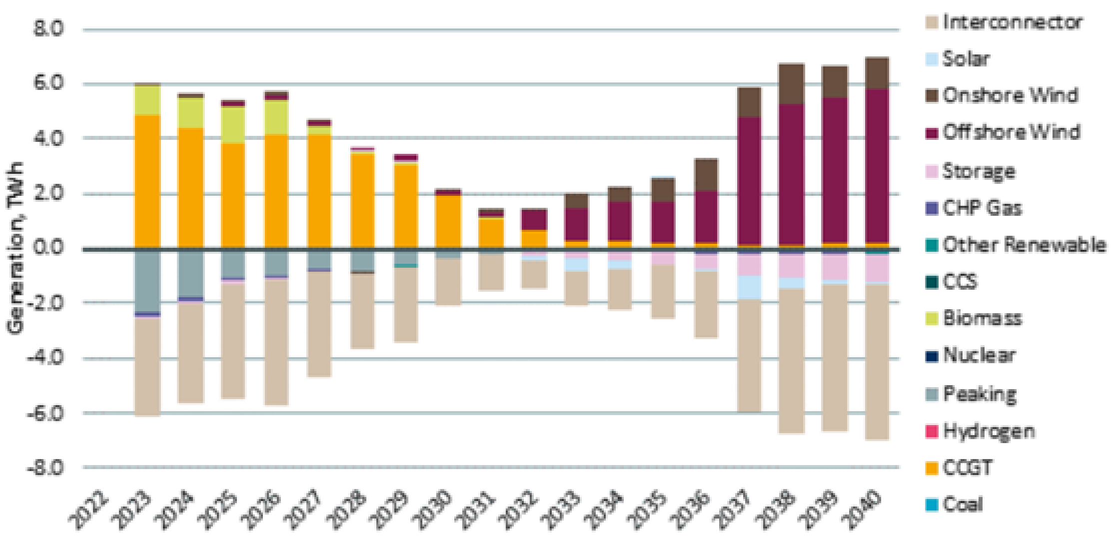


Figure 6 - Generation (Factual –Counterfactual) Consumer Transformation. Source: LCP/Frontier

5.20. Table 4 summarises the benefits to consumers from these changes under both the CT and SP scenario. The system modelling supports our assessments indicating potential benefits from the changes proposed in CMP308, and suggests there are potentially greater benefits if decarbonisation proceeds more slowly than anticipated.

Table 4 - Consumer benefits from applying BSUoS charges to Final Demand only

	Consumer Benefits, NPV terms
Steady Progression	£370m
Consumer Transformation	£320m

CO_2 Emissions

5.21. The impact on electricity sector CO_2 emissions of changing from the *status quo* to a situation where all BSUoS charges are levied on Final Demand is derived from our consultants' modelling. However, the assessment and valuation of these impacts in the context of the UKETS and EUETS which have caps on emissions is complex. In particular, the modelled electricity sector emissions in GB and abroad should be seen as first-round effects. The second-round effects relate to subsequent adjustments that must be made within the entire economy. For an economy like the UK with a cap on emissions in participating sectors, if electricity sector emissions increase (decrease) then other sectors must decrease (increase) emissions for the cap to be met.

5.22. We asked a specific question regarding modelled electricity sector emissions during our consultation, and we took the responses to that question into consideration. Most respondents supported our modelled assessment and agreed with our assessment of the decarbonisation impacts of this policy, though some respondents questioned our assumptions and approach to emissions in interconnected markets. Following engagement with stakeholder feedback, we are comfortable that our analysis is robust and takes a reasonable approach to estimating emissions. We consider that there is an important principles-based rationale that supports investment being most efficient when distortions are removed, and we would expect that our organisational objective of facilitating Net Zero at least cost is more likely to be achieved in a market with fewer distortions. We therefore do not consider further analysis to be needed.

Modelled Emission Quantities

5.23. The modelled impact of CMP308 on carbon emissions is shown below for the CT scenario in Figure 7. We can see that when estimated emissions for interconnected generation are accounted for, CMP308 leads to lower overall emissions, with the reduced emissions from peaking plant and interconnected generation slightly outweighing increased emissions from CCGTs.[92] The SP scenario sees more CCGT emissions, alongside lower emissions associated with interconnector flows and less peaking plant emissions compared to the CT scenario[93]. We received feedback from a stakeholder who felt that the assumptions around the carbon intensity of interconnected generation used in our report did not reflect their views on the likely future realities. Following further consideration, we are comfortable that our analysis is robust and takes a reasonable approach estimating emissions.

5.24. For context, if the change in average annual emissions modelled in CT over the first 5 years of analysis are compared to the current UK ETS cap (156 mtCO2e) they equate to 0.65% of UK traded emissions.

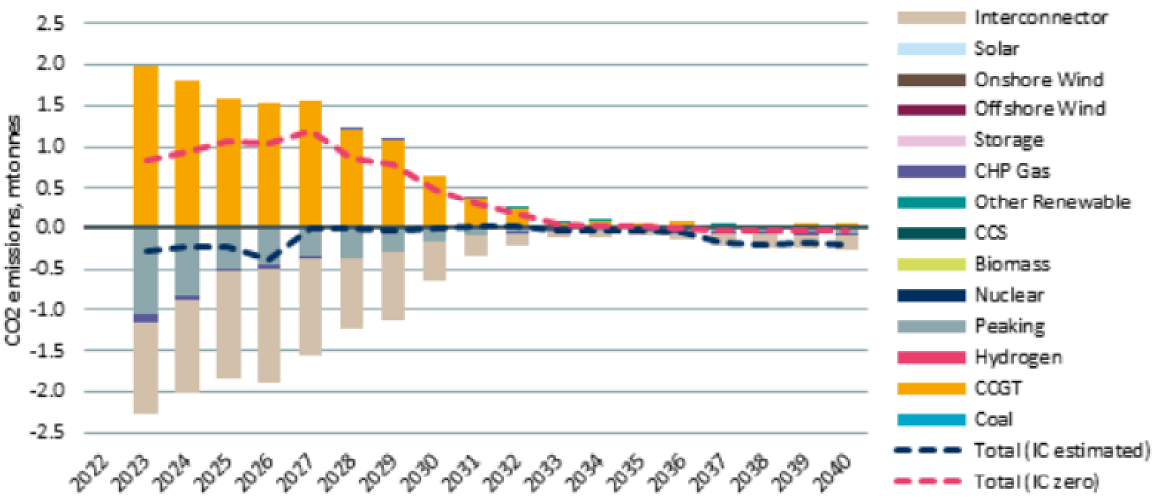


Figure 7 - CO_2 Emissions (Factual-Counterfactual). Source: LCP/Frontier

5.25. The analysis of the removal of BSUoS charges from generation indicates an increase in sectoral carbon emissions when calculated on a GB territorial basis (not including the change in emissions in interconnected markets). In the figure above this is shown by the dashed pink line.

- There is an estimated increase of 8 million tonnes CO_2 equivalents during the modelled period. For context, this is 0.15% of the CO_2 equivalents emitted by the economy if the

[92] The emissions associated with changing interconnector flows are estimated. It is assumed that the generators flowing over the interconnectors have the same carbon intensity as the nearest domestic generator within the GB merit order. This would broadly lead to interconnector emissions that are higher during periods of high demand on the GB system when emissions are higher, and lower when demand is lower.
[93] More information on the results for the SP scenario are present in our consultants' report

UK follows the Climate Change Committee (CCC) planned emission pathway for Net Zero.[94]

- The SP scenario modelling estimates an increase in emissions of 12 million tonnes CO_2 equivalents (0.23%) of CCC pathway carbon emissions in the same period.

5.26. If we include an estimate of the change in emissions outside GB as well as GB emissions, overall carbon emissions are reduced by the proposed reforms, by 2 million tonnes under the CT scenario and by 4 million tonnes under the SP scenario.

Valuation of emissions

5.27. The overall system benefits depend on the approach taken to emissions associated with power traded across interconnectors.

5.28. As highlighted above, if there is an increase in GB power sector emissions there must be reduction elsewhere in the UK economy in order to meet the cap. As a result, this induces additional CO_2 abatement, at an additional cost, in those sectors which are now abating more than they otherwise would have. Table 5 shows the estimated wider system costs under the CT scenario, which include a societal valuation of carbon emissions based on the UK cost of carbon abatement. Note there is a great deal of uncertainty about precise abatement costs, and this is reflected in the low and high series shown within brackets in Table 5.

5.29. Emissions were originally costed using 2018 BEIS traded-carbon appraisal values. BEIS recently published new carbon appraisal values, which are different[95] to those used in the cost benefit analysis that we published in July.[96] When the report was prepared in July, the relevant carbon values were the 2018 figures. Since then, BEIS has updated carbon values and so we have updated the analysis to reflect those updated values.[97] The new and old values are shown in slide 4 of the LCP supplementary slides[98] and their impact on NPVs in slide 16.

[94] Sixth Carbon Budget - Climate Change Committee (theccc.org.uk)
[95] The new carbon values are seven times greater than the previous traded values.
[96] UK ETS traded and non-traded emissions are now valued at the same value.
[97] The substantial change in estimated system benefits following BEIS's publication illustrates the sensitivity of monetised benefits to assumptions.
[98] https://www.ofgem.gov.uk/sites/default/files/2021-12/2021-11-12%20Ofgem%20BSUoS%20results%20-%20updated%20carbon%20appraisal%20values%20incl%20market%20price%20%28003%29.pdf

Table 5 - Wider benefits from applying BSUoS charges to Final Demand only

With 2020 Carbon central series values (low and high series estimates in brackets)	Wider benefits for society, including emissions in other markets, NPV (£m)	Wider benefits for society, not including estimate of emissions in other markets, NPV (£m)
Steady Progression	£1,860 (£1,400 to £2,310)	-£1,240 (£10 to -£2,500)
Consumer Transformation	£810 (£600 to £1,020)	-£1,070 (-£190 to -£1,950)

5.30. We asked our consultants to estimate the baseline costs that relate directly to the electricity system, by removing the carbon abatement effects. These remaining costs represent the actual resource cost of running the system, such as materials, supplies, equipment, technologies and facilities, purchase of priced carbon allowances. This approach suggests the electricity system would save £400m in costs if CMP308 were implemented.[99]

5.31. A national assessment is limited to GB territorial emissions, and emissions changes outside of the UK as a result of this policy are excluded. In this assessment significant additional costs are attributable to CMP308. This is due to the additional 'unpriced carbon' costs attributed to the electricity system. These costs stem from the requirement for the economy as a whole to achieve its carbon targets. Using BEIS's updated figures, the final result is that there is an additional cost of £1,070m, with the unpriced carbon detriment valued at £1,470m. This illustrates that the valuation of the abatement of energy production emissions becomes the dominant factor in GB 'wider system costs' rather than the direct costs of the energy system.[100]

5.32. With the scope of the assessment encompassing emissions changes in interconnected countries, both the carbon emissions and the cost of meeting emission targets will decrease across UK and interconnected countries, when taken as a whole. For example, the proposed marginal costs of abating carbon in France are like those in GB.[101] If emissions have the same cost of abatement in interconnected countries the system impact would be valued at a saving of £810m.

[99] This analysis estimates the system cost saving as £400m in the CT scenario and £960m in SP.
[100] Initially, this had a limited effect and our consultants' report showed a saving of £290m using previous BEIS emissions factors, with the unpriced carbon detriment valued at £110m. For the SP scenario, using the new BEIS values, similar unpriced carbon detriment adjustments change a system cost saving of £960m to £1,240m additional cost.
[101] Carbon values literature review (publishing.service.gov.uk)

Contracts for Difference

5.33. The modelling indicates that low carbon support payments, both in the form of Renewable Obligation Certificates and Contracts for Difference (CfDs), will reduce if BSUoS charges are removed from Large Generators.[102] This represents a sizeable portion of the modelled change in composition of consumer costs.

5.34. One of the assumptions in our consultants' modelling is that CfD contracts are adjusted for generators with early and bespoke contracts. Under existing CfD contracts, generators that currently pay BSUoS charges receive an annual strike price adjustment to protect them from fluctuations in average BSUoS charges paid by GB generators using a Strike Price indexation formula. This adjustment is designed to make the CfD contract broadly neutral to variations in BSUoS charges in the long-term.

5.35. We are aware of provisions in the CfD contract that could allow continued compensation payments for BSUoS charges ("BSUoS adjustment payments") to existing CfD projects for a period after Large Generators cease having to pay BSUoS. This BSUoS adjustment issue was highlighted by BEIS in their recent consultation ahead of CfD Allocation Round 4[103] (AR4). In that consultation, BEIS signalled its intention to amend the standard terms of the CfD contracts to remove BSUoS adjustment from the existing adjustment formula for any CfD contracts awarded in that round, in the event CMP308 is approved.[104] This amendment was incorporated into the final version of the CfD standard terms for AR4 published by BEIS on 25 November 2021. The effect of this change is that successful AR4 applicants will not receive any compensation for BSUoS charges from the date CMP308 takes effect.

5.36. We agree with the view of BEIS that it would not be appropriate for CfD generators to continue to receive BSUoS adjustment payments for these charges through the CfD if they no longer have to pay them, and consider that this applies to not only future, but also existing contract holders. Significant levels of continued BSUoS adjustment payments following the implementation of CMP308 could result in windfall gains for the generators concerned, at a cost to consumers.

5.37. It is our understanding that, without changes to existing CfD contracts, the BSUoS adjustment payments would continue to compensate existing CfD holders for a period after the date our decision

[102] Biomass generation is expected to benefit from the removal of BSUoS, meaning it generates more. Existing CfD-supported wind plant may also benefit. This is because although strike prices will be adjusted down to reflect BSUoS costs being removed, the current CfD adjustment to strike prices is based on volume-weighted BSUoS costs and wind-weighted BSUoS charges are higher.

[103] Contracts for Difference for Low Carbon Electricity Generation: Consultation on further drafting amendments to the CfD contract for Allocation Round 4 (publishing.service.gov.uk) . More general information on the round can be found at https://www.cfdallocationround.uk/

[104] Contracts for Difference (CfD) Allocation Round 4: standard terms and conditions - GOV.UK (www.gov.uk)

takes effect. It will require contract amendments to align the removal of BSUoS adjustment payments with the date that our decision takes effect.[105]

5.38. If, for any reason, existing CfD contracts were not amended to remove the entitlement to BSUoS adjustment payments with effect from the implementation of CMP308, the continued payment of the BSUoS adjustment payments would significantly reduce the consumer benefits of this proposal. This is because there would be a period following implementation of CMP308 where CfD generators would continue to be compensated for costs that they would no longer be incurring.[106]

5.39. Respondents to our consultation felt it would not be appropriate for CfD generators to receive BSUoS adjustment payments, once CMP308 was implemented, for periods for which they were not liable for BSUoS charges. Some respondents cautioned against complete removal of the adjustment payment mechanism without appropriate time for reconciliation. One respondent suggested the adjustment payments should continue for approximately one year after CMP308 is implemented to account for the lag effect in historic vs. actual BSUoS prices. Another respondent felt that mplementation of CMP308 in April 2023 should be contingent on all existing CfD generator agreements being amended to remove the BSUoS compensation, and should not go ahead if unwarranted payments would be made at consumer cost. Another felt a final decision on this proposal must be made prior to the upcoming CfD sealed bid window[107] opening, something we have aimed to accomplish with this publication.

5.40. Ofgem does not have a role in the required contractual changes as these are contracts between generators and the Low Carbon Contracts Company (LCCC), and as such consider the exact contractual arrangements to be a matter for the LCCC, the counterparty to CfD contracts. But, we broadly consider that any payments under this mechanism that are made to reimburse CfD holders for costs they incurred in the spirit of the arrangements, rather than due to overcompensation for a cost they have not incurred (i.e. BSUoS adjustment payments for generators who are no longer to pay BSUoS charges), should not be considered as additional consumer costs.

5.41. In the minded to decision, we noted that the LCCC (the counterparty to CfD contracts) would engage with generators to effect the requisite contract changes to remove the entitlement to BSUoS adjustment payments in the event that we were to approve CMP308. Such adjustment payments would no longer be necessary if generators were no longer paying BSUoS charges.

[105] BSUoS adjustment payments are based on historic data, with the changes to BSUoS charges taking around 14 months to be reflected in Strike Prices. The adjustments are based on average BSUoS charges paid by all generation, which may differ from the costs that fall on individual generators, who will face BSUoS charging costs related to their particular dispatch patterns.
[106] Because of this lag in BSUoS adjustment, generators would continue to be paid BSUoS for 24 months after they no longer pay it, partly at the full rate, and partly at a reduced rate.
[107] Longest Timeline | Contracts for difference CfD (cfdallocationround.uk)

5.42. We also noted that if the relevant contract changes were not implemented, the continued payment of the BSUoS adjustment payments would significantly reduce the consumer benefits of CMP 308 and result in windfall gains by the relevant CfD generators. At that time, our estimates were that in the worst case scenario the extent of the windfall gains could be in excess of £200 million. Since the minded to decision, BSUoS charges have risen significantly such that failure to effect the contract changes could potentially result in windfall gains in the region of £400m. Consultation responses agreed that windfall gains for generators would not be appropriate and we received no responses to the contrary.

5.43. We have continued to engage with LCCC to seek to satisfy ourselves that any undue benefits associated with the BSUoS adjustment payment provisions in CfDs can be removed. In advance of starting any formal contract amendment process (and whilst awaiting our decision on CMP308), LCCC has been engaging with CfD generators. LCCC have advised us that each generator, with whom they have had discussions to date, has agreed in principle that undue benefits associated with the BSUoS adjustment payment provisions in the existing contracts should be addressed. Whilst LCCC has not yet engaged with every CfD counterparty, they have done so with a significant proportion, accounting for over 85% of CfD generation capacity by full year 2024/25. LCCC is confident that the necessary contract amendments can be implemented in good time before the implementation of CMP308 on 1 April 2023 such that the estimated consumer benefits associated with CMP308 should not be significantly reduced and windfall gains not made by relevant CfD generators.

Impact on commercial arrangements

5.44. The proposed removal of BSUoS charges from generation was a key recommendation of the BSUoS Task Force in September 2020. We published our agreement in principle in December 2020, confirming that April 2023 would be an appropriate target for implementation of the reforms, but making clear an impact assessment and further assessment of the detail was needed. Our previous work on the TCR set out our views that residual and cost recovery charges should not be paid by generation.

5.45. We are therefore of the opinion that a typical market participant will have understood that change could occur to the BSUoS charging arrangements for a number of years prior to a 2023 implementation and will have had the opportunity to consider their approach to these uncertainties, including the effect on their commercial arrangements. The majority of respondents to our consultation confirmed our view that prudent market participants will have understood that these changes could occur, and almost all respondents agreed that the proposed changes in CMP308 have been incorporated into supplier decisions.

5.46. Respondents broadly agreed that implementation of CMP308 from April 2023 was predictable to market participants, with the direction of travel set out by Ofgem when the Task Force's findings were accepted. Most agreed April 2023 was sufficient notice for this proposal to be implemented, and felt that the implementation date of April 2023 would not lead to significant risk of delayed benefits due to double payments and/or windfalls. We did, however, receive feedback from large users expressing concerns about the potential for windfalls due to longer-term hedging strategies. We do not consider this a material risk, as we consider it likely that generators will have sufficiently incorporated their expectations around BSUoS reform into their longer-term power contracts.

Security of supply in the monetised benefits

5.47. It is assumed in our quantified work that the current GB security standard (Loss Of Load Expectation of three hours per year) is maintained throughout the modelling period (though with some prudence factored into the capacity requirement calculation) and that the current Capacity Market regime remains in place.

Other stakeholder views on the modelling

5.48. The majority of respondents agreed that our consultants' modelling represents a reasonable view of the potential effects of this modification. Most respondents agreed that Ofgem has duly considered all relevant consumer and system benefits. However, one respondent stated that our Impact Assessment does not include analysis on how CMP308 might impact interconnector investment. We do not foresee significant impacts to interconnector investment, particularly as recent interconnector development investment rounds have used a Cap and Floor regime that provides a minimum rate of return for investors. Another respondent pointed out that our modelling did not cover how CMP308 will benefit transmission-connected battery storage. We consider that changes to BSUoS charges are likely to lead to more efficient investment in battery storage once the playing field is levelled, and that there may be an improved investment environment. Our modelling included only limited numbers of transmission-connected batteries but we do not consider this to undermine the findings, nor do we expect batteries to experience significantly different effects from this proposal than other technologies.

Limitations, key assumptions and risks

5.49. Careful modelling work helps us to make sets of assumptions explicit and provides a route for stakeholders to challenge these. There are limits to the precision and accuracy of any modelling, but it facilitates engagement with affected parties. Assessing the impacts of significant change to a complex system is inherently uncertain and there are limitations to the analytical approaches set out in this document, and in any other alternative approaches. Full discussion on the limitations to the assessment of net benefits and distributional analysis are set out in the published report from our consultants published in July 2021.

5.50. As with all modelling, our consultants' work uses a number of simplifications and assumptions, covering areas such as future system demand, generation capacity, market prices and renewables build out. It is our view that a key use of this modelling is to help us understand the "moving parts" or mechanisms affected by a decision, and to help us to understand and quantify other assessments we make. We do not expect this modelling to perfectly replicate future conditions, but rather see it as an additional tool to support a qualitative decision. The modelling provides insight on the potential impacts of the decision and the interactions between the arrangements and possible system developments. We do not believe the current BSUoS values undermine our analysis or the benefits case of reform.

5.51. Our consultants have been clear on the limitations of analysis (see Section 5 of their report). In particular, we note the following limitations, assumptions and risks:

- Use of an agent-based approach. This approach seeks to replicate actual investor behaviours and dispatch decisions. This will not perfectly reflect the real world. However, since the model was commissioned by the Department of Energy and Climate Change[108] in 2010, it has been used extensively by Government and industry and has been central to a number of decisions and processes. We therefore do not have concerns and consider the limitations well understood.

- The Envision model is a sophisticated representation of dispatch and investment decision in the GB market and it allows for electricity flows across interconnectors in response to price signals from Europe. However, a simplifying assumption is that the interconnectors have the same carbon intensity as the nearest domestic generator within the GB merit order. We consider the approach taken is sufficiently accurate and proportionate to the needs of our decision. We have discussed alternative assumptions with stakeholders and remain of the view that our model makes reasonable assumptions. We have presented results with and without changes to interconnected market emissions, thereby presenting the effect this modification may have on power sector emissions and associated abatement costs in other markets, whilst recognising the fact that emissions are calculated on a territorial production basis. We understand the potential range of costs possible, and we are comfortable, as set out in our assessment above, that the market and investment benefits of this change would still outweigh the costs seen.

- Other FES scenarios, notably 'Leading the Way', the scenario with the fastest decarbonisation, and 'System Transformation', which relies more on system rather than behavioural change, have not been modelled. As indicated, we think that the scenarios chosen are sufficient to illustrate the main mechanisms and impacts.

- Optimism Bias. The consultants' estimates rely on a smooth transition in contracts (supply, generation, existing CfDs etc.). It is possible that in the implementation of the modification, anticipated benefits are not as high as anticipated if any industry parties find a way to avoid

[108] The predecessor to the Department for Business, Energy and Industrial Strategy ('BEIS')

passing savings through to consumers. Where relevant, such as in the case of CfDs, we have estimated the magnitude of the consumer risks.

- Global gas prices remain extremely high, and this has led to a retail energy cost crisis. These current conditions in the energy market have greatly increased balancing costs. There has been no exploration of the impact on CMP308 if these conditions persist into the implementation period. Higher balancing costs might lead to greater BSUoS charges, which in the *status quo* arrangements would in turn lead to more significant differences in the costs faced by Large Generators and other generation that is not liable for BSUoS. This would lead to greater distortions to investment and dispatch. While this would be the case in the *status quo* arrangements, the current higher balancing costs and resulting BSUoS charges would present additional challenges for suppliers if CMP308 was approved, as the impacts would fall on demand. The distortions between generator types would not be present.

- We recognise that at a time of high gas prices, the case for investment in CCGTs, which is predicted by the model might not seem intuitive, but we note recent CM outcomes and think the direction shown - that Large Generators may be at less of a disadvantage than in the current regime - is likely to hold true. We would expect the investment and dispatch impacts of the different BSUoS costs of Large Generators of other technologies, such as Wind or Solar and their non-liable counterparts to reduce.

Implementation Costs

5.52. We understand that the ESO also aims to implement CMP308 using a new ESO billing system to unlock process efficiencies, though we recognise these efficiencies are not proven. While CMP308 will increase charges on suppliers, given it is an increase in an existing charge we would not expect significant systems changes for industry. We address changes to CfD arrangements earlier in this document.

Hard-to-monetise costs and benefits

5.53. The monetised results do not represent the full impact that we expect to see from this change. We think this reform, if implemented, may have the following hard-to-monetise impacts:

- **Improved Generation Economics and Efficiency**: Removing BSUoS charges from Large Generators will reduce distortions in the signals faced by Large Generators, which we would expect to help in the delivery of more efficient markets, including flexibility markets. Better price signals will promote more efficient investments in the longer term. On a more practical level, the removal of BSUoS charges from generators may reduce the burden on generators and developers and may free up resource allocated to BSUoS charges forecasting by large generators, potentially facilitating savings, but we understand some stakeholders are sceptical about whether such benefits would be realised where supply and generation operations are carried out within single businesses.

- **Energy System Resilience:** Our quantitative analysis indicates that the proposed reforms would have a significant impact on interconnector flows, with imports across interconnectors being displaced by Large Generators in GB once BSUoS charges are no longer levied on them. We consider that it is beneficial for the financial resilience of domestic generation it to be larger rather than artificially smaller due to a charging distortion.

- **System complexity**: No longer levying variable BSUoS charges on generators and having it feed into wholesale price bids will reduce system complexity, and complex interactivity. This may in itself help with system efficiency and contribute towards keeping bills down for consumers. Reduced system complexity may help more targeted policy measures to work effectively and make systemic risks easier to identify. This benefit may be amplified if CMP361, or a similar modification that removes BSUoS charge volatility is approved.

- **Transparency:** With approximately half of BSUoS costs no longer being passed through to consumers via wholesale prices and instead being charged to suppliers directly, the costs faced by consumers would be more transparent. It is not clear to consumers how much their suppliers have paid for BSUoS within their wholesale costs, as this would require knowing how much the generator concerns had built into their offers to account for BSUoS charges on export. In a large portfolio, this could be the average of a large number of purchases, each with different estimates. With all BSUoS charges falling on demand, users on fixed contracts may have a clearer view of the BSUoS costs built in, depending on the detail of the contract, while users with pass through contracts may see what has been built in in more detail or may get the direct costs with full transparency.

- **Other costs and benefits:** We understand that Large generators and suppliers (where the contract is not pass-through) build premiums into their offerings to account for uncertainty in the future cost of BSUoS charges. This is reasonable practice to account for uncertain future costs. With CMP308, generators will no longer need to build premiums into their wholesale offerings. We acknowledge that the effect of any inefficiencies due to transaction costs, forecasting costs and risk premiums associated with BSUoS charges being applied to large generators are difficult to capture. Following CMP308, suppliers will need to take a view on a larger value of BSUoS costs. This may be further improved by CMP361, as, depending on the solutions developed, suppliers could have a more predictable, less volatile forward view of BSUoS charges. We will assess that modification separately in due course.

- **Supplier exposure to fluctuations in BSUoS charges:** Increasing exposure to BSUoS charges for suppliers under the CMP308 CUSC modification may present challenges, due to the greater costs that will fall on them. However, we do not see this as a greatly different role for suppliers – they are already required to forecast BSUoS charges in order to create their customer offerings.

CMP361, seeks to address this by delivering another key recommendation of the second BSUoS Task Force – fixing BSUoS charges in advance. Again, we will assess this in due course.

- **Remaining Distortions**: CMP308 does not address the benefits obtained by Behind The Meter Generation in offsetting demand BSUoS charges, but does mean exports from generation situated behind the meter pay BSUoS charges at the same zero rate as all other domestic generation types, improving competition for generation. We will continue to monitor this effect to ensure consumers are protected from any growing distortions.

Summary

5.54. The potential reform is expected to provide a benefit to GB consumers in the region of £320m Net Present Value in a Net Zero compliant scenario (or £370m NPV if progress on decarbonisation is slower), and so the energy system is made significantly more efficient. In effect, the market has been biased towards small distributed generation and energy imports and power emissions exported. Correction of the distortion leads to emissions rising in GB, though these are balanced by lower emissions in interconnected European markets. We note the carbon impacts of this modification are complex but estimate that it makes a positive contribution to reducing power sector greenhouse gas emissions. As set out in our assessment against our statutory duties, we consider it to be reasonable to consider CO_2 emission impacts on interconnected markets.

5.55. On its own, the modification has some non-monetised benefits in the areas of resilience, simplification and transparency. A small distortion would still remain to benefit BTMG, which can reduce demand BSUoS charges, and we aim to monitor this in case further engagement with industry on this issue is required. We consider these factors to be less important than the quantified consumer and system benefits but recognise the significance of the volatility issue to suppliers and end consumers, particularly in the context of high market prices.

6. Distributional analysis

Section summary

This section reports the distributional impacts of placing BSUoS charges solely on demand, particularly on end consumers but also on the impacts on other market participants such as suppliers, generators and CfD bidders. It takes into account different user archetypes including those that may be more common in the future and identified bill impacts, based on the static influence of BSUoS charge increases, and the dynamic influence of other changes such as reductions in the wholesale price.

Consultation questions asked in our minded-to decision

16. Do you have views on the impacts of this proposal on end consumers, including large users and vulnerable users?
17. Do you agree with our assessment that reduced costs to generators are likely to feed through into lower wholesale prices?
18. Do you agree with our assessment that this policy will not have any significant material impacts on vulnerable users?
19. Do you agree with our assessment that this modification is unlikely to lead to any significant impacts on essential services or supply chains?

Overview of distributional effects

6.1. Our consultants' modelling sets out a full assessment of the impacts on a broad selection of consumer archetypes. These archetypes were first used in the impact assessment which we carried out as part of the TCR. This earlier framework has been expanded from simple views of annual and peak volumes to full half-hourly profiles, in order to properly capture the variable pricing of BSUoS charges.

6.2. Table 6 below summarises the archetypes considered. As with all archetypes, these are useful assessment tools but are not intended to cover the full range of possible customer profiles within all segments. For that reason, our consultants have also carried out qualitative assessments on specific segment impacts. The details of the specific profiles are not presented but a high-level summary is reproduced below. Overnight consumption is important, as those with a high overnight consumption face a greater impact from the increased BSUoS demand charge.

Table 6 - Net demand for each consumer archetype and the proportion of that user archetype's consumption which is consumed overnight

User group	Annual net demand (kWh)	Share of overnight consumption*
1. Domestic – Low consumption	1,800	21%
2. Domestic – Medium consumption	2,900	13%
3. Domestic – High consumption	4,300	16%
4. Domestic – High Economy 7	7,100	25%
5a. Domestic – Medium Solar PV	2,055	36%
5b. Domestic – Medium Solar PV with storage	1,148	43%
6. Domestic – Medium Electric vehicles	4,170	34%
7. Domestic – Heat pumps	5,447	21%
8. Commercial – Low consumption	10,000	9%
9. Commercial – High with onsite generation/storage	8,312	16%
10. Commercial – High without onsite generation/storage	25,000	10%
11. Commercial – Light industrial HV-connected	5,000,000	25%
12. Industrial - EHV-connected without onsite generation/demand management	50,000,000	33%
13. Industrial – T-connected without onsite generation/demand management	100,000,000	33%

Note: **The proposed change has the highest upward impact between 11pm and 7am (wholesale blocks 1 and 2) for the majority of scenarios at most points in the year. Hence customers who consume a disproportionate share of their energy during this time will see marginally worse impacts.*

6.3. As in the previous chapter, we have focussed on the results for the CT scenario[109] as it is compliant with GB's Net Zero commitments. Bill impacts can be separated into a static increase from BSUoS changes (shown in teal in the Figures below) and dynamic impacts after a number of other, usually offsetting, cost changes. The modelling suggests the net impact for individual network users from these reforms is relatively small, though it varies over time and depends on the scenario. For a domestic customer with low, medium or high consumption (1800kWh, 2900kWh and 4300kWh each year), our analysis suggests an expected annual increase of £0.59 and a reduction of £0.58 and £0.52 respectively once dynamic impacts are factored in.

[109] Full detail on the distributional impacts for the SP scenarios is available in our consultants' report.

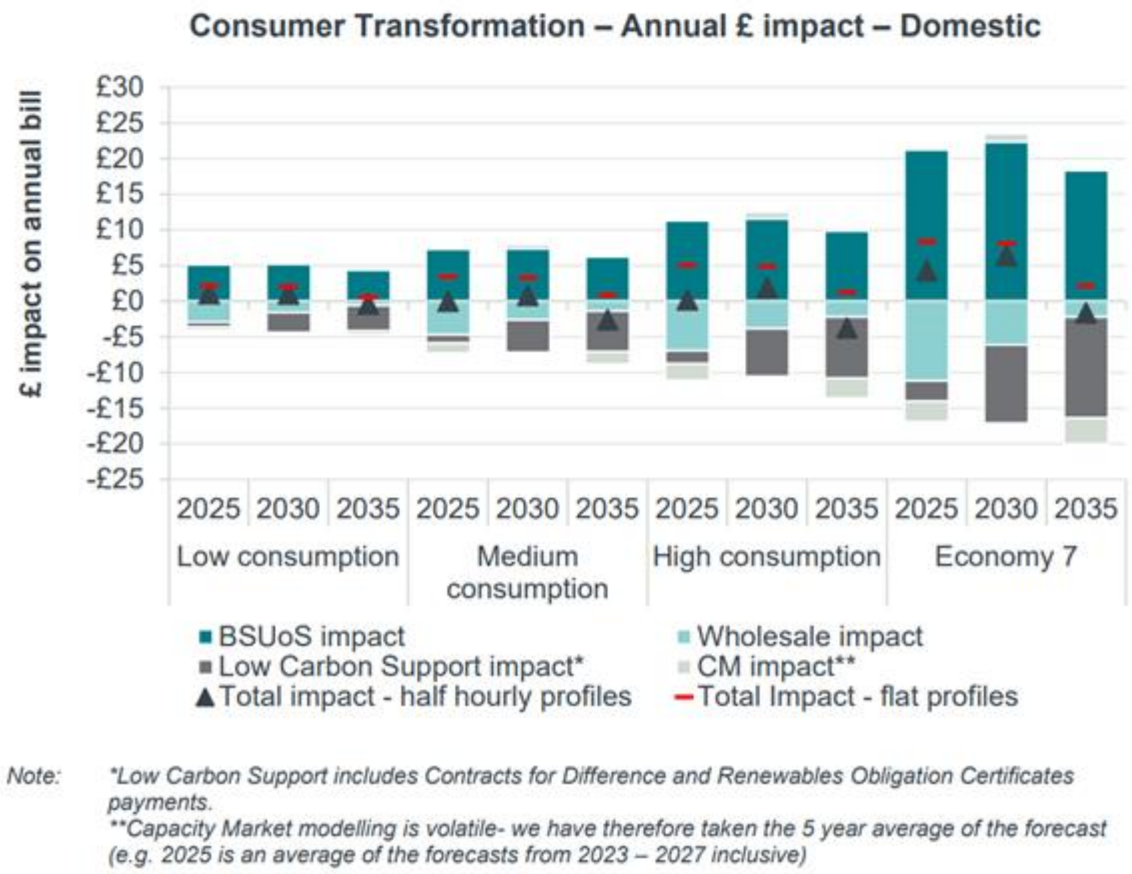


Figure 8 - Consumer Transformation – Annual £ impact – Domestic. Source: LCP/Frontier

6.4. As described above, as BSUoS charges are generally higher overnight, the largest increases in static annual BSUoS costs are faced by users with flat or night-weighted consumption profiles. One result of this is that domestic users with greater overnight usage, such as users with Economy 7 meters, with heat pumps or with electric vehicles are likely to pay more, but any effect is minimal once dynamic benefits are accounted for. For example, a high consumption Economy 7 user would pay about £3.00 extra each year (or as little as £0.07 each year in SP). An EV owner using 4,170kWh, with 34% overnight consumption, would pay just £2.46 more per annum (£0.47 in SP).

6.5. Our report highlights that all domestic low carbon technologies (LCT) increase the concentration of demand into the night period when BSUoS charges are highest, driving a small increase in cost across domestic users with LCTs. We would note that while these costs are small, they may be significant to some users, particularly if they are implemented alongside other increases, such as changes to the price cap.

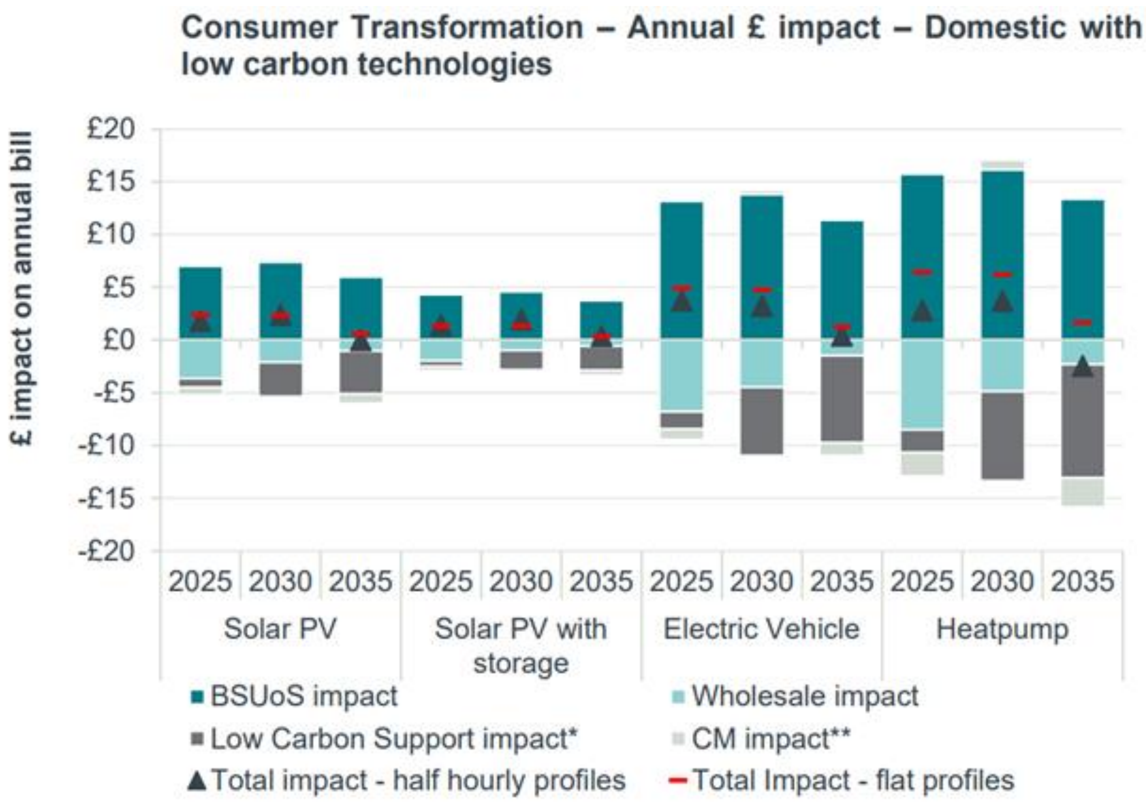
6.6. For completeness, we note that this increased overnight cost effect may be addressed by the BSUoS Task Force's other key recommendation, which was that BSUoS charges should be set in advance and recovered as a flat and fixed, rather than variable, volumetric charge. This is being progressed through a separate CUSC modification, CMP361, and nothing in this decision fetters our discretion with regards to that separate decision.

6.7. As noted above, Ofgem have a statutory duty to consider persons who:

- have a disability or are chronically sick;
- have a low income;
- are of pensionable age; or
- reside in rural areas.

6.8. These consumers sit across the usage spectrum. We would particularly note that our previous work for the Targeted Charging Review[110] suggested that individual household electricity consumption is a poor indicator of deprivation. Given the low estimated financial impacts on domestic users, and the fact that our archetypes span a very broad range of consumption, we do not consider this policy change to have a significant impact on vulnerable users, something respondents to our consultation agreed with. Users of Economy 7 meters may be more likely to be off the gas grid or in rural areas, or may be more likely to be users that are taking steps to reduce their energy bills due to financial constraints.

[110] See chapter 3 of our TCR Final Decision
https://www.ofgem.gov.uk/sites/default/files/docs/2019/12/full_decision_doc_updated.pdf



Note: *Low Carbon Support includes Contracts for Difference and Renewables Obligation Certificates payments.
**Capacity Market modelling volatile- we have therefore taken the 5 year average of the forecast (e.g. 2025 is an average of the forecasts from 2023 – 2027 inclusive)

Figure 9 - Consumer Transformation - Annual £ impact - Domestic with low carbon technologies. Source: LCP/Frontier

6.9. The static increase in the BSUoS charge element of bills ranges from £20 per year to £52 per year in the CT scenario as BSUoS is higher in this scenario[111]. As commercial consumption profiles for these enterprises are skewed to the day, the dynamic impact of BSUoS charging changes result in a benefit of £2.04 per year for a small commercial user, £9.16 per year for a large commercial user without onsite generation and storage and £4.90 per year for a large user with onsite generation and storage. Were a flat profile adopted, annual costs would increase by £8.74, £21.84 and £7.26 respectively. Very broadly, the benefits of this change are linked to the volumes used, but also to the proportion used at night when BSUoS charges are expensive. This would not be the case for a flat volumetric charge like that proposed under CMP361.

[111] An assessment of the impact on the bills of commercial customers is presented in 3.3.3 of the consultants' report accompanying this document.

6.10. Section 3.3.4 of the consultants' report deals with industrial customers' charges but there is some compensation from offsetting savings. As might be expected, the shift of BSUoS to demand increases bills for these customers. Figure 9 shows the various factors affecting final bills for the CT scenario. The analysis suggests a light industrial HV-connected user with annual consumption of 5GWh might see an increase of around £2.3k in the CT scenario, taking into account all dynamic impacts such as lower wholesale costs. This is an increase of c.£0.46/MWh (see Table 7 below).

6.11. A transmission-connected[112] user consuming 100GWh per annum might see an increase of c.£87k per year under the same scenario, or roughly £0.87/MWh increase. This is largely driven by the high night usage of these users (c.33%) and the very high volumes used.[113] Impacts in the Steady Progression scenario are much lower, with changes of just £56 per year (£0.01/MWh) for the HV users and £15,885 (£0.16/MWh) for the transmission-connected user.

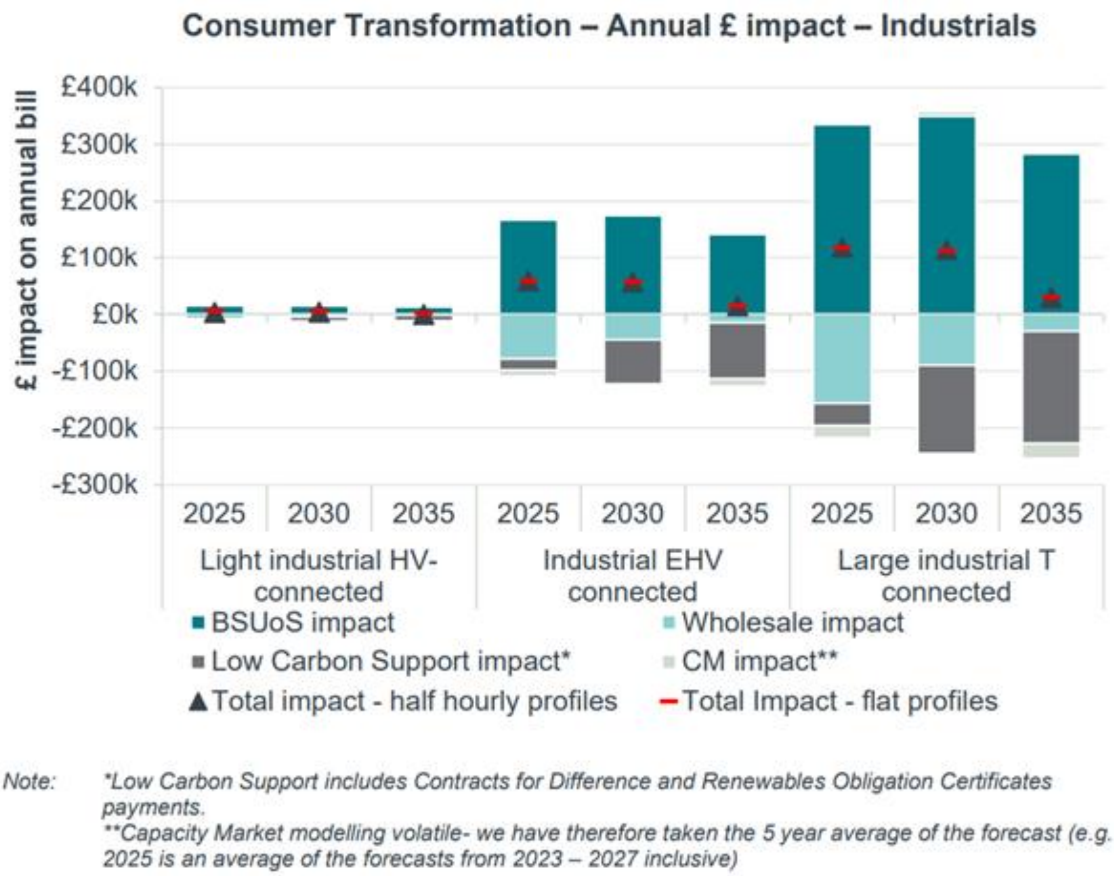


Figure 10 - Consumer Transformation - Annual £ impact – Industrials. Source: LCP/Frontier

[112] Here the archetype itself is for an example transmission connected user, rather than simply a Large generator.
[113] For context, in more typical market conditions where power costs average £40/MWh, a demand consumer using 100GWh per annum might expect to spend £4m per annum on wholesale electricity costs before policy or network costs are added.

6.12. Further information can be found within the consultants' report, as well as relevant discussions on the assumptions made and the limitations of the analysis.

Table 7 - Comparison of bill impacts from BSUoS charges and after dynamic impacts by large user category

Average 2025-35	**£/MWh**		
	Light industrial HV-connected	**Industrial EHV connected**	**Large Industrial T connected**
Profile assumption	More peak consumption than off-peak	Flat	Flat
BSUoS cost increase	2.85	3.23	3.23
After dynamic impacts bill increase	0.46	0.87	0.87

Impacts on specific industry groups

6.13. As described above, we consider our consultants' modelling of distributional impacts to be appropriately comprehensive, though we recognise there are a number of user groups that warrant further consideration.

6.14. We recognise suppliers will need to build expectations of BSUoS charges into their offerings and will be buying power forward a number of years. While the work of the BSUoS Task Force has been well-signalled, it will not have been received and interpreted by all industry parties equally. It is reasonable to assume that suppliers may not all be able to immediately reflect changes to BSUoS charges in their tariffs, though we would expect a typical supplier to have considered the potential for changes in this area. Power that they have already bought may have BSUoS cost elements at some level built into the wholesale prices. Equally, fixed price tariffs are unlikely to have fully accounted for changes to BSUoS charges.

6.15. As a result, we think it is possible that some windfall effects may exist, but are reassured that respondents to our consultation felt the implementation date of April 2023 provided industry parties with sufficient notification that windfall effects would not be material, and also felt that generators would have reflected expected market developments in BSUoS charging in their prices.

6.16. We note that generators who are planning to enter into future CfD auctions may need to factor different costs into their bids if this change is approved. Any delay in the removal of compensation mechanisms associated with BSUoS charges could lead to reductions in the consumer benefits estimated, and that due to the details of the compensation process, there could be periods where BSUoS charges are entirely payable by demand but where compensation is still paid to some generators. We would also note, as set out in our wider systems modelling, pass-through of generator cost reduction may not be complete. This may particularly be the case where the marginal generator does not face BSUoS charges. We address these issues in more detail in our earlier assessment section.

6.17. As noted above, we recognise that this modification would lead to the reallocation of costs to demand users at a time when many large and energy intensive users are under particular pressure due to energy costs. We consider that our modelling suggests this will not unduly add to end user costs, due to reductions in other energy system costs.

6.18. Respondents to our consultation broadly agreed that this proposal will have a positive impact on end consumers, but some noted that large users who optimise consumption during off-peak hours but do not have BTMG will fare worse than consumers with more typical daylight working hours profiles. We understand that some large users consider broader BSUoS reform, such as that including the changes set out in CMP361, may provide mitigation.

6.19. Respondents agreed with our assessment, though one respondent suggested that wholesale market volatility means a direct reduction may not be evident after implementation.

6.20. We do not consider the cost impacts of this modification to be of the level of materiality where supply chain disruption could be expected. Firstly, this is a change that has been long expected and signalled, and one with a future implementation date. Secondly, we think the expected impacts on consumers are likely to be low, and more so if additional BSUoS charging reforms reduce the volatility of the charges. Respondents who answered this question agreed with this assessment, though one respondent considered the potential for significant impacts on essential services or supply chains would be present if decisions on CMP308 and CMP361 were not made in a timely fashion with appropriate notice provided.

7. Implementation

Section summary

This section covers implementation of this proposal. We are approving the modification for implementation on 1 April 2023, and below discuss some of the considerations around this.

Consultation questions asked in our minded-to decision

20. We would note that increases in demand costs will need to be incorporated into the price cap methodology. Do you have any views on this area?
21. Do you agree with our proposed implementation date of 1 April 2023? Please provide your reasoning.

Implementation timing

7.1. The CMP308 Final Modification Report sets out the Workgroup's considerations as to whether the proposed implementation timescales are appropriate, and summarises the consultation responses received, a majority of which support implementation on 1 April 2023.

7.2. Respondents to our consultation broadly agreed April 2023 was the right implementation date, though many noted the links to CMP361. Some respondents gave their views that CMP361 and updates to Ofgem's price cap methodology should be implemented at the same time as CMP308 to realise the full benefits of CMP308 and reduce risk for suppliers. Others expressed a preference that CMP308 is implemented on 1 April 2023, regardless. In addition to an appropriate inclusion in the price cap, some stakeholders felt implementation should be contingent on the removal of any undue compensation to CfD holders through the BSUoS adjustment payment provisions.

7.3. We consider reform has been well signalled to network users since the Task Force final report and our response in 2020, and respondents agree that these changes are likely to be expected by the market, with the potential for windfall gains and losses to market participants if later implementation is chosen. We recognise that some Workgroup participants felt there was a risk that too short an implementation timeline may result in suppliers picking up more costs than they should. For example, they might pay for larger post-CMP308 demand BSUoS charges, despite BSUoS charges for generation having already been included in their wholesale costs for that period, though we note responses to our consultation suggest this is a low risk. Later implementation also brings the risk that suppliers have sold fixed price contracts that do not factor in additional BSUoS costs. We think April 2023 implementation provides a long enough transition to keep these effects to a minimum while ensuring consumers benefit from change swiftly

7.4. We would note that a clear possibility of reform has been signalled to network users since the Task Force final report and our response in 2020. We note that Workgroup discussions also indicate that reform has been expected and "priced in" by some parties. We would therefore expect change to be priced into longer term contracts by some parties to some degree and have concerns that a different implementation date may lead to windfall gains and losses to market participants.

7.5. We recognise that some Workgroup participants felt there was a risk that too short an implementation timeline may result in suppliers picking up BSUoS costs that have already been included in their wholesale costs for that period. In addition, some considered that suppliers might find that they have sold fixed price contracts, not factoring in additional BSUoS costs. We think April 2023 implementation provides a long enough transition to keep these effects to a minimum while ensuring consumers swiftly benefit from change.

7.6. Our December 2020 open letter agreed that April 2023 would be an appropriate target for the implementation of the Task Force's recommendation to recover BSUoS charges from Final Demand only and that remains our position.

Practical implications of implementation

Final Demand Data

7.7. Two BSC modifications, P419 & P395 cover the need for exemptions and declarations to allow the proposed treatment of Final Demand to work effectively. We will assess these modifications against the relevant objectives in due course.[114]

Residual Cashflow Reallocation Cashflow (RCRC)

7.8. The Task Force recommended the formation of a BSC issues group after the conclusion of the key BSUoS charging reform CUSC modifications to "implement Ofgem's decisions and investigate changes to the RCRC mechanism in light of the Task Force's recommendations". We would again suggest that industry consider whether any changes are needed to RCRC charging arrangements.

The Energy Price Cap

7.9. Changes to who is liable for BSUoS charges would flow through automatically under our current Energy Price Cap. The allowance in the cap for BSUoS charges would increase (reflecting the cost increase for suppliers), but this would likely be offset by decreases in the allowances for wholesale and low carbon

[114] We publish our decision for P419 alongside our publication of this decision on CMP308.

policy costs. The overall effect should therefore be largely neutral, with expected benefits for consumers in aggregate, but we recognise the risk that some additional costs may fall on consumers by way of one of the other risks outlined in this document, or that there could be increased costs during the transition where contracts contain energy purchases made under the previous regime.

7.10. Given the current market conditions and the general impacts on supplier cashflow, we are mindful of the need to ensure this change is reflected in the price cap effectively, to ensure that suppliers, generally, are not adversely affected by the impact of CMP308. Given the links to CMP361, there is the possibility of further BSUoS related changes to the price cap being needed for the April 2023 implementation of CMP308. We think therefore it best not to commit to a specific treatment of CMP308 in the price cap as yet, but rather to ensure we continue to engage with suppliers and other parties on the merits of changes to the price cap methodology following CMP308 approval.

Ongoing monitoring and evaluation

7.11. It was the view of some industry participants that if this modification was implemented, monitoring would be needed to assess whether the expected reduction in wholesale prices is equivalent to the additional cost of BSUoS charges to consumers; checking that consumers were not disadvantaged by this modification. We note that our modelling did not indicate full pass-through via wholesale prices – this was expected because Large Generators do not always set the marginal price in wholesale markets – but did show that consumer benefits were plausible due to reduced distortions. We also noted earlier in this document the presence of distortions concerning BTMG. We will continue to carefully monitor all market arrangements as per our duties to ensure consumers are protected, but do not propose specific monitoring arrangements related to this decision.

Implications of 2023 implementation on consumers

7.12. As noted above, we recognise that suppliers' customer offerings may include fixed elements that mean increased liability for BSUoS changes cannot be passed through, or cannot be passed through immediately. We recognise that many suppliers will have agreed contracts of one, two or more years that extend beyond the implementation date of this modification. We also recognise they may have purchased power over periods that extend beyond this implementation date, which in some cases, may have some element of BSUoS costs built in. While all of these situations mean there is the potential for pass-through of the changes to be imperfect, feedback to our consultation suggests this change was largely expected, and so windfall impacts are unlikely to be material. We therefore do not consider there to be any reason not to progress with these changes on the current timeline on this basis.

7.13. We note that the AR4 CfD allocation round sealed bid window is expected to open very soon. We remain of the opinion that a decision on CMP308 now gives bidders useful additional information for this auction.[115]

We have considered whether further delay to implementation might be needed to ensure that charging changes do not have significant adverse impacts, particularly for vulnerable or large users. We do not expect such impacts, and consider 1 April 2023 to be a suitable date for implementation.

[115] Longest Timeline | Contracts for difference CfD (cfdallocationround.uk)