Final Report

Second Balancing Services Charges Task Force

30th September 2020

nationalgridESO

Foreword

Ofgem asked the Electricity System Operator (ESO) to launch this Industry Task Force to provide analysis to support decisions on the future direction of Balancing Services Use of System Charges (BSUoS). This report marks the final output of the Second Balancing Services Task Force and the culmination of almost two years of effort. It builds on the output of the First Balancing Services Task Force and follows the publication of Ofgem's Final Decision on their Targeted Charging Review Significant Code Review. While to most, the economics and workings of network charging methodology is an exceedingly dry topic, it cuts to the very heart of some of the most fundamental questions we as an industry need to address in our pursuit of net-zero carbon; 'who should pay for our critical infrastructure and how should the charge be constructed?' Ofgem will review the recommendations included in this report and will then publish a response signalling the policy direction for the future of balancing services charges.

As the pace of change in the energy sector accelerates to achieve net-zero carbon targets, system and network charging methodologies must keep up to ensure they are fit for purpose in a changing landscape. I'm incredibly proud of the work of the Task Force, the output of this report and the recommendations contained within it that lay the groundwork for a BSUoS charging methodology that's fit for the future and delivers consumer value.

Transparency has been our guiding principle and a key goal of the Task Force has been to bring together a broad representation of industry to address the issue and the divergent views on the best way forward. To that end membership of the Task Force included charging experts with a wealth of experience in different sectors of the energy industry and its work was led by the ESO. We also put engagement with wider industry at the heart of the Task Force's work and a key aim for us throughout the report development process was to ensure we took stakeholders on the journey with us through podcasts, attendance at a multitude of industry forums and publishing all meeting materials on the Charging Futures website. Alongside this engagement we have run a five-week consultation period to further garner industry views and inform the recommendations contained within this report.

The recommendations set out in this final report have been informed by and include a wide range of feedback from industry and we would like to thank you for your time and input to this piece of work as well as your ongoing support in the development of a new BSUoS charging methodology.

Colm Murphy
Task Force Chair
Market Change Delivery Manager
National Grid Electricity System Operator

Executive summary

The Second Balancing Services Task Force was launched by the ESO in January 2020, in response to Ofgem's request of 21st November 2019[1], and built on the work of the First Balancing Services Task Force (Jan 2019 – May 2019)[2].

The initial timelines specified by Ofgem required the Final Report to be submitted by the Task Force in June 2020. Following the disruption caused by COVID-19 Ofgem decided to pause the Task Force's work pushing the submission date of this Final Report back to September 2020.

The Task Force had two deliverables to consider:

1) **Who should be liable for Balancing Services Charges, and;**
2) **How these charges should be recovered.**

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

On Deliverable 2, how should the charge be levied the Task Force have concluded that a volumetric fixed BSUoS charge would deliver overall industry benefit, and that the total length of the fix and notice period should be around 14/15 months in length.

There was extensive debate whether the charge should be similar to the Transmission Demand Residual methodology (i.e. £/site, based on size) or volumetric (i.e. £/MWh). The Task Force discussions are laid out in a table in the body of the report which shows assessment of each approach against the TCR principles. Ultimately, the distributional impacts of a banded charge and the complexity it introduces led The Task Force to agree by majority that the most appropriate way of recovering the charge is through a volumetric (£/MWh) charge. This is particularly relevant for a charge which is recovering costs related to an energy service.

Fixing BSUoS charges ex ante requires the ESO to manage the volatility risk on behalf of BSUoS payees for the duration of the fix period. It is the Taskforce's view that the BSUoS tariff would be fixed so all payees know the £/MWh fixed tariff in advance and the ESO carries any cost not covered by the fixed fees as no party knows exactly how much Balancing Services expenditure will be over the period. This creates an over/under recovery risk, and associated cash-flow costs, for the ESO to manage. The Task Force recognised a compromise needed to be made between certainty for suppliers and shortfall minimisation for the ESO. This led to a recommendation for a 14/15-month total fix and notice period.

Notice to industry of the changes to the methodology is important; the Task Force recommend that two years' notice from the point of Ofgem's response is given, this notice period would include notice of the fixed charge such that tariffs begin on 1st April two years after Ofgem's response. The Task Force noted that it's important that Ofgem's response gives clear indication on the future BSUoS arrangements.

The Task Force's conclusions and the reasoning given in this accompanying report will be reviewed by Ofgem to determine the next steps for changes to the Balancing Services charging methodology.

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

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

[1] https://www.ofgem.gov.uk/system/files/docs/2019/11/open_letter_on_the_balancing_services_charges_taskforce.pdf
[2] http://www.chargingfutures.com/media/1348/balancing-services-charges-task-force-final-report.pdf

Contents

Introduction

How are GB Balancing Services costs currently recovered? – The BSUoS Methodology

The Transmission Licence allows NGESO to recover costs in respect of Balancing Services activity. It does this through Balancing Services Use of System Charges, otherwise known as BSUoS charges. The methodology for the recovery of these costs is set out in Section 14 of the Connection and Use of System Code (CUSC).

BSUoS is a charge that the ESO levies on suppliers and generators in order to recover costs incurred through system balancing actions in real time and for longer duration contracts for balancing services. A BSUoS price is calculated for every half-hour settlement period by dividing the balancing costs incurred during that settlement period by the total volume of energy imported from and exported to the NETS in that settlement period.

As of April 2021, assuming the implementation of Ofgem's TCR Direction through CMP333 and following approval of modification CMP281, BSUoS charges will be levied on suppliers in respect of their gross energy import, on non-exemptible generators (all transmission connected and large distribution connected) on their energy exports and imports and on Storage users for imports excluding those for the purpose of operating their storage facility. CVA metered Storage users will continue to pay BSUoS on their exported volumes. Interconnector BMUs and smaller distribution connected generators do not face BSUoS charges.

The ESO produces a monthly forecast of total Balancing Services spend, and historical BSUoS charges are available on the ESO website. The Task Force noted that some companies forecast HH BSUoS costs "in house".

First Balancing Services Task Force

Ofgem launched the first Balancing Services Charges Task Force on 28th November 2018. The overall objective of the Task Force was to provide analysis to support decisions on the future direction of BSUoS, against three deliverables. These deliverables were:

1. **Does BSUoS currently provide a useful forward looking signal?**
2. **Potential Options for charging BSUoS differently, to be cost reflective and provide a useful forward looking signal**
3. **Feasibility of charging potentially cost reflective elements of BSUoS to provide a forward-looking signal**

The First Task Force was run and chaired by the ESO and included industry participants, customers who paid BSUoS charges, consumer representatives and Ofgem, providing a breadth of opinions and expertise on Balancing Services Charges. The Task Force worked collaboratively and transparently to ensure that the wider industry was informed on how the Task Force progressed and could contribute to the Task Force work programme. All the information regarding the First Task Force, including the full report and membership, is available on the Charging Futures website.

What did the First Balancing Services Charges Task Force conclude against the Three Deliverables?

Deliverable 1. - When assessing the current BSUoS charge, the first Task Force concluded that it *"does not currently provide any useful forward-looking signal which influences user behaviour to improve the economic and efficient operation of the market"*[3]. In order to reach this conclusion, the Task Force collectively identified five main reasons why this is the case. Firstly, the current BSUoS charges are hard to forecast, secondly that current BSUoS charges were complex, thirdly that they were increasingly volatile, fourthly that other market

[3] Balancing Services Charges Task Force – Final Report. National Grid ESO, 31 May 2019, Page 5

signals are more useful and so take precedence, and finally that the current BSUoS charge applies to all chargeable users of the transmission system on an equal basis.

The Task Force also identified two unintended effects of BSUoS on the wider market: market parties exposed to BSUoS are adding a "risk premium" to their costs to mitigate the risk of an uncertain BSUoS bill, and that some parties might react to a subtle signal particularly during lower volume periods overnight. The Task Force concluded that these impacts on the market do not "result in behaviour that is of benefit to the system or ultimately to consumers"[4].

Deliverable 2. – When answering the issues posed by deliverable 2, the Task Force assessed whether individual elements of BSUoS had the potential "for being charged more cost-reflectively and hence could provide a forward-looking signal"[5]. The Task Force took four such elements for further consideration: locational transmission constraints; locational reactive and voltage constraints; response and reserve bands; and response and reserve utilisation. The Task Force discounted some other potential cost elements which were viewed to be cost-recovery.

Deliverable 3. - The Task Force then assessed the feasibility of these four costs being charged in a manner which provided an effective forward-looking signal. The Task Force utilised four evaluation criteria: i) the charging being cost-reflective; ii) providing said effective signal; iii) being practical and proportionate; and iv) other considerations i.e. reflecting consumer needs, facilitating competition and/or innovation and being future-proof.

The Task Force concluded that "whilst there were some theoretical advantages to all four potential options identified, the implementation of each of these would not or could not provide a cost reflective and forward-looking signal that would drive efficient and effective market behaviour"[6].

There was also no evidence that the issues that exist currently in market arrangements (i.e. the charge being hard to forecast, complex, highly volatile, etc.) would cease to apply in any of the four costs that the Task Force identified. Indeed, moving elements of charges to targeted groups of users may exacerbate these issues.

First Task Force – Overall Conclusion

The first Task Force concluded that it was not feasible to charge any of the components of BSUoS in a more cost-reflective and forward-looking manner that would effectively influence user behaviour to help the system and/or lower costs to customers. As such, the Task Force members concluded that BSUoS should be treated as a cost-recovery charge. This conclusion serves as the starting point for the second Task Force, underpinning any work carried out during the second Task Force.

TCR Principles

In November 2019, Ofgem published their final decision on the [Targeted Charging Review Significant Code Review (TCR SCR)](). Alongside this decision, Ofgem set out a need for a Second Balancing Services Charges Task Force, in a letter to industry[7], to build upon the work undertaken by the initial Task Force. Since launching the TCR SCR, Ofgem have clearly articulated three main principles for assessing changes to residual network charges.

These are:

- Reducing harmful distortions,
- Fairness, and
- Proportionality and practicality.

[4] ibid
[5] ibid
[6] ibid, Page 7
[7] https://www.ofgem.gov.uk/system/files/docs/2019/11/open_letter_on_the_balancing_services_charges_taskforce.pdf

Ofgem state that "*these principles were developed and refined through consultation to incorporate stakeholder concerns, and ensuring our definitions are consistent. Ofgem has statutory duties which must be adhered to when making decisions of this nature and these principles align with those duties*"[8].

Ofgem published guidance on what these three principles mean and the Task Force used these principles to assess potential options for charging BSUoS. This is evidenced throughout this report.

Deliverables for the Second Balancing Services Task Force

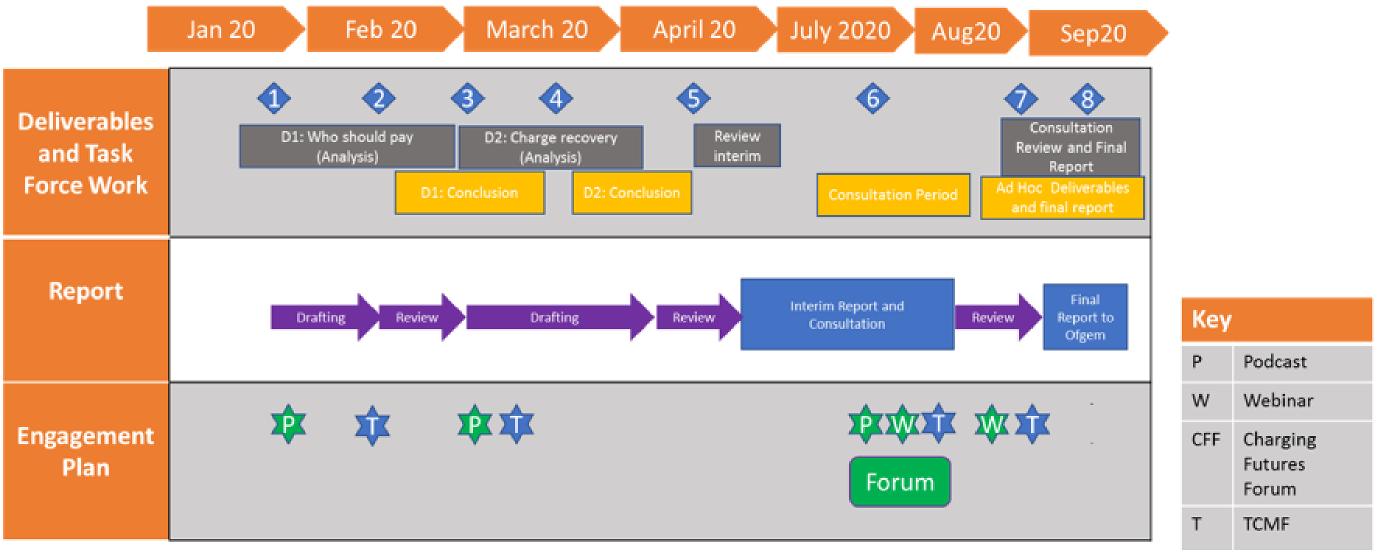
In order to further develop the conclusions of the First Task Force, Ofgem requested that a second Balancing Services Task Force, led and chaired by National Grid ESO, should focus on two additional deliverables. Ofgem agreed with the first Task Force's conclusion and "accept that at present it is not possible to send useful forward-looking signals through balancing services charges"[9]. In November 2019, Ofgem also underlined that whilst they accepted the findings of the first Task Force, they felt further investigation was required into who should pay the charge if it is cost recovery, and how the charge should be recovered.

As such, the second Task Force (and this report) explored two specific questions.

1. **Who should be liable for Balancing Services Charges, and;**
2. **How these charges should be recovered.**

The second Task Force have taken a similar approach to that of the first Task Force, tackling and debating specific issues as well as undertaking qualitative and quantitative analysis to try to answer these questions. Options outlined in the report have been assessed using the TCR principles. The Task Force were also advised to remain aware of developments in other network charging areas, particularly of Ofgem's decision that network residual charges (for TNUoS and DUoS) should be paid by Final Demand only

The Task Force Workplan and Industry Engagement



The workplan undertaken by the Task Force is illustrated in the above timeline. Following the disruption caused by COVID-19 Ofgem decided to pause the Task Force's final report pushing the submission date of the Final Report back to September 2020. The Task Force met 6 times between January 2020 and July 2020

[8] Ofgem Publication on TCR Principles, Page 1
[9] Ofgem Open Letter on the Second Balancing Services Charges Task Force, 21 November 2019, Page 1

in order to complete the initial work and analysis needed to inform initial conclusions on the two deliverables. A wide range of resources from these meetings, including slides, meeting summaries, headline reports and podcasts are available here. A consultation period was then run from 22nd July 2020 to 26th August 2020 to which 35 consultation responses were received, 2 of which are confidential and will be submitted directly to Ofgem, the remaining responses are published in full alongside this final report.

Task Force members engaged various industry forums in order to deliver key messages and share updates on the direction of travel for the Task Force, including TCMF, DCMDG, Renewable UK, Energy UK and the Energy Intensive Users Group, a full list of all Task Force engagement is contained in the Appendices of this report. The Task Force has also been in regular touch with consumer groups such as Citizens Advice, who have attended meetings to contribute to discussions.

Two industry webinars were held on the 20th July and 11th August 2020 to introduce the consultation and provide Q&A opportunities for industry. These webinars were hosted through the Charging Future forum.

The conclusions detailed in this final report will be explored through an upcoming Charging Futures forum event in November to enable industry to ask questions on the final report and to discuss next steps.

Consultation Feedback

All 33 non-confidential responses to the Task Force's consultation can be found alongside this final report. The Task Force discussed points raised in the responses during three meetings after the close of the consultation. Points were raised on topics throughout the report and the Task Force's discussions and thoughts about these points are captured under "Consultation Feedback" headings (like the one above).

Deliverable 1: Who should pay Balancing Services Charges?

1. Who should pay Balancing Services charges?

The First Task Force concluded that GB balancing services costs currently recovered through the *Balancing Services Use of System* (BSUoS) charge could not be charged in a forward-looking manner and did not provide useful signals to industry parties. Therefore, they should be considered a “cost recovery charge”.

This conclusion has prompted Ofgem to review the charging base for Balancing Services charges using the TCR principles: Reducing Harmful Distortions, Fairness and Practicality and Proportionality. The Task Force were also advised to remain aware of developments in other network charging areas, particularly of Ofgem’s decision that network residual charges (for TNUoS and DUoS) should be paid by Final Demand only.

Through the TCR, Ofgem have defined Final Demand as being “electricity which is consumed other than for the purpose of generation or export onto the electricity network”[10]. The CUSC and DCUSA modifications CMP334 and DCP359 have developed a more detailed definition of Final Demand and are, as of September 2020, with Ofgem awaiting an Authority decision. As the Task Force debated Deliverable 1, they determined that it was sensible to use the same definition of Final Demand as the one indicated by Ofgem and would lean on the work of CMP334 and DCP359 once a decision on these modifications is made.

How the Task Force approached Deliverable 1 and Considered Historical Analysis

Principle based analysis was used primarily to inform the Task Force conclusions. Modelling the impacts of the Task Force recommendations was deemed too complicated and costly given the short timescales and data available. The Task Force recommend that Ofgem undertake modelling to inform their impact assessment for Final Demand only paying BSUoS. This is particularly important to determine whether the analysis originally produced for the CMP201 CUSC modification still holds.

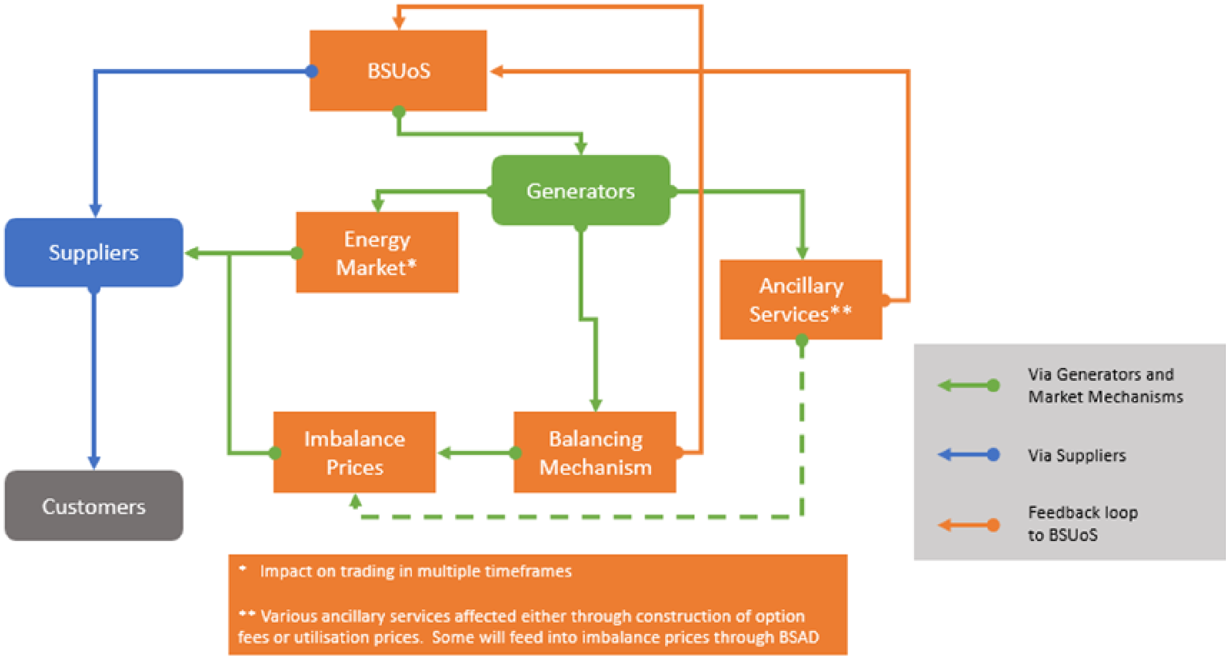
CMP201 was a CUSC modification initially raised in 2011[11] which sought to move Balancing Services Charges wholly onto final demand and which was not approved by Ofgem. At that point, Ofgem concluded that ‘we are concerned that at this time the potential benefits this would bring would not be material enough to offset the potential costs to consumers from implementing the modification’. This concern resulted from Ofgem’s view that in the short-term, increasing GB generation relative to European counterparts through removing Balancing Services obligations would increase demand for GB generation and therefore bring more expensive, marginal plant into merit.

The Task Force considered whether, despite the CMP201 concluding removing BSUoS could result in additional costs for consumer, an updated assessment of the CMP201 model would conclude differently. The Task Force noted that total Balancing Services expenditure has increased significantly since this analysis was produced and differentials between GB and interconnected markets have also increased. Additionally, the original analysis had not considered other market impacts such as interconnector congestion revenues or Capacity Market payments, which would be relevant now. Alongside this, the capacity and number of interconnectors between GB and continental Europe has increased. The Task Force were aware that increased BSUoS expenditure would also increase the severity of the short-term consumer impacts that had concerned Ofgem in their initial decision making on CMP201. The Task Force agreed that more quantitative analysis would be desirable but short timeframes and the complexity of the analysis required did not make this possible.

To complement the principle-based analysis, the Task Force also discussed case studies from GB and European markets to understand how equivalent charges for balancing services are levied.

[10] https://www.ofgem.gov.uk/system/files/docs/2019/12/full_decision_doc_updated.pdf p55
[11] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp201-removal

Transaction Costs and Cost Recovery Principles



The Task Force explored the various "pass through" routes that BSUoS charges take, when levied on generators, to reach the end consumer. The Task Force agreed that BSUoS charges paid by generators would be reflected in wholesale market, ancillary services and BM markets' pricing. The Task Force considered that the presence of these costs could create harmful distortions particularly where the charges were not applied consistently to all participants competing in those markets. Crucially, as BSUoS should be considered as "cost recovery", in line with TCR conclusions on residual charges, the most efficient approach is for Final Demand only to pay. This avoids the more complicated approach associated with passing costs through from generators, via multiple market mechanisms, to suppliers and ultimately to the end consumer.

The Task Force concluded that the pass-through process generated additional transaction costs, i.e. those costs that are incurred as a result of having a BSUoS liability, compared to a methodology where those costs were paid by Final Demand only. These transaction costs are widely expected to be very small in the context of the overall Balancing Services cost recovery pot but because organisational structures differ between parties these costs are difficult to quantify.

Presence of Harmful Distortions both between different types of GB generator and between GB and Interconnected Generators

GB generators connected to the distribution system do not pay BSUoS on their exports. However, they may compete directly with transmission connected generators in Ancillary Services, Balancing Mechanism and wholesale markets who do pay. The Task Force concluded that removing BSUoS charges from transmission connected generators would correct this existing market distortion. This will improve competition which will enable more economic and efficient outcomes, thereby delivering consumer benefits.

The Task Force also noted that whilst the BSUoS charging base could be expanded to include distributed generation this would create a new distortion, as behind the meter generation would remain exempt from the charges. It is not practicable to include behind the meter generation in the charging base as there are no complete records of the assets and MWh output at behind the meter sites and no guaranteed commercial relationship between an on-site generation owner and a party liable for BSUoS. The Task Force concluded that the most appropriate way to remove any potential distortion in energy markets was to exempt all generators from BSUoS. The Task Force also noted in making this recommendation that collecting BSUoS wholly from final demand as a volume charge would create a similar new distortion boundary as behind the meter generation could earn a BSUoS avoidance embedded benefit roughly double the current level, while network connected generators could not.

The Task Force also considered whether there could be a distortion between generators located in Great Britain compared to generators based in continental Europe. Comparing equivalent balancing services charges levied on generators in other European countries was not straightforward, but investigation into the countries directly connected or soon to be directly connected to the GB system via interconnectors indicated that GB was an outlier in the amount generators pay for balancing services. Most European countries included in the report this subset was drawn from[12], levied some balancing services charges entirely onto demand.

Any differences in how generators and other parties competing in wholesale and balancing services markets across national borders are exposed to BSUoS charges will directly distort competition, if the charges do not reflect differences in costs caused by those parties. As the original Task Force established that BSUoS charges do not send meaningful market signals, it was felt that any differences in cost recovery between competing parties would create a distortion.

The Task Force agreed that removing balancing services charges from generators would contribute to reducing a harmful distortion between GB generators and interconnected generators.

Country	Do Generators pay Balancing Services charges?	How does the charge compare to GB?	Comment
France	No	n/a	French generators pay very little network charges at all.
Netherlands	No	n/a	
Belgium	Yes	£0.87/MWh (35% of the GB charge)	Balancing services costs in Belgium are fixed in advance and are purely for black start and power reserve costs.
Ireland	No	n/a	
Norway	Yes	£0.19/MWh (8% of the GB charge)	Levied based on historic 10-year output data and therefore unavoidable
Denmark	Yes	£0.46/MWh (18% of the GB charge)	Fixed charge to contribute to reserve costs

Consultation Feedback

Of the majority of consultation responses which favoured levying BSUoS onto Final Demand only, most cited the removal of harmful distortions between GB transmission generators and European generators as the key factor in that decision.

Who pays Balancing Services charges and Decarbonisation

Impacts on decarbonisation are an essential consideration for all industry changes as work continues to decarbonise the sector in line with net-zero targets. Hence the Task Force considered the impacts on decarbonisation of two different BSUoS charging scenarios. The two scenarios considered were: 1) expanding the BSUoS charge to distributed generators and 2) the levying of BSUoS charges on 'final demand' users only.

As part of Ofgem's Targeted Charging Review, Frontier Economics undertook a sensitivity analysis to consider the impact on consumer benefits, seen through the TCR full BSUoS reforms, if there was less onshore renewable investment after the government announced these technologies would no longer be eligible for the Contracts for Difference (CfD) scheme.[13] The sensitivity analysis -assumed a 50% reduction in new unsubsidised onshore renewable capacity and demonstrated that there would be a reduced benefit to the consumer whilst meeting decarbonisation targets., In the analysis, this is driven by the replacement of

[12] https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/mc-documents/TTO_Synthesis_2018.pdf

[13] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-decision-and-impact-assessment

reduced cheaper onshore renewable capacity with more expensive, subsidised offshore renewable capacity. The reduced consumer benefit is the differential in unit costs between onshore and offshore renewables.

Since this analysis concluded, the Government have announced the re-introduction of some onshore renewables into the CfD scheme. Whilst this move is widely considered to support the UK in meeting decarbonisation targets and may correct some of the hypothetical disincentive identified in the TCR analysis, it is worth noting that the capacity of the CfD 'pot' for onshore renewables is yet to be announced, and that the contracts for difference only have a duration of fifteen years. In addition, the CfD is only accessible to generators of 5MW and above. This excludes many smaller generators, typically inclusive of non-energy professionals such as community groups and landowners. This would mean that, should BSUoS charges be levied on distributed renewable generation, the risk premia and transaction costs that the Task Force have identified would still need to be factored into an investors financial model for projects both within and without the CfD scheme.

Hence, although maybe not to the same extent as that hypothesized in the Frontier Economics sensitivity analysis due to the CfD support, the levying of BSUoS charges onto distributed generation is still likely to disincentivise some investment in onshore renewables and hinder progress towards decarbonisation targets.

System Costs (Carbon) - using high BEIS carbon appraisal value				
	Steady Progression		Community Renewables (Alternative FES)	
	Total to 2040	NPV to 2040 (£2016)	Total to 2040	NPV to 2040 (£2016)
Difference between Baseline and TGR & Partial BSUoS reform	£182m	£119m	£494m	£326m
Difference between Baseline and TGR & Full BSUoS reform	£455m	£294m	£1,025m	£659m
Net Impact on System Costs of Extending BSUoS to Distributed Generation	+£273m	+£175m	+£531m	+£333m

With regard to the application of BSUoS charges to 'final demand' users only, the Task Force concluded that the impact on decarbonisation was likely to be smaller, however there would likely be a reduction in imports over the interconnectors, which for the purposes of GB carbon accounting are treated as zero-carbon. This means that levying BSUoS charges on final demand only, resulting in the displacement of some interconnector import by domestic transmission connected generation, would be counted as a more carbon intensive outcome. In the interconnected countries of France, Belgium and the Netherlands the marginal plant is usually a gas or coal generator, much like in GB. This means that in situations where imports to GB are reduced (as a result of changes to the BSUoS methodology), less conventional plant on the continent would likely be required and more in GB, without displacing any renewable generation in either country. The net impact of such a move would be globally carbon neutral. The Task Force agreed that decarbonisation was wider than individual countries' carbon accounting methodologies and that imported electricity is not actually zero carbon when generated by conventional plant on the continent.

Application of BSUoS charges to 'final demand' users only would also avoid the associated risk premia and transaction costs being included in offshore renewable project financial models outside of the CfD scheme and aid progress towards decarbonisation targets. As a counterpoint, removing BSUoS charges from transmission connected generation will feed through to wholesale price reductions, leading to a worsened business-case for price-taking distributed renewable generators.

Consultation Feedback

One respondent to the consultation queried the Task Force's views that imported electricity is not actually zero-carbon believing that interconnectors support decarbonisation by allowing access to renewable generation which originated in another country. The Task Force noted this view and clarified the wording in the final report to reflect their view that marginal generation in any country is less likely to be renewable; zero fuel cost renewable generators are typically lower in the merit order and therefore not marginal plant.

Consequently, marginal imports over interconnectors would be as likely as marginal generation in GB to come from fossil fuel burning generators leading to a globally net zero carbon outcome. For any interconnected market running on completely renewable or low carbon generation the difference removing BSUoS costs would make from the marginal plant is highly unlikely to take interconnected imports out of merit as the price differentials would be expected to be very large.

Quantifying the Impact of Risk Premia

Quantitative analysis can provide evidence allowing comparisons to be made between potential options. The Task Force made use of agreed assumptions about the time horizons used to forecast BSUoS and risk premia to quantify the overall cost of BSUoS if levied on different subsets of industry parties.

Ultimately, the analysis showed that if the assumptions of Weighted Average Cost of Capital (WACC) were the same for both generators and suppliers and BSUoS was forecast over the same time horizons there was a small benefit to charging BSUoS solely on Final Demand. The Task Force agreed that generators were more likely to be concerned of the volatility in BSUoS on a half-hourly basis and that levying BSUoS on suppliers only, as seen through the model, when the forecast time horizons were the same, would reduce the scale of the risk to the market as a whole. To improve the real-world applications of the analysis, the Task Force made the assumption, using evidence collected by the Competition and Markets Authority (CMA)[14] based on the period 2007 – 2014, that suppliers had a slightly higher WACC than generators. Whilst this difference was small the Task Force acknowledged that any benefit (from a more efficient cost pass through of BSUoS) could be offset by higher costs of financing.

Consequently, it was acknowledged that assumptions around WACC had a decisive bearing on the outcome of the analysis and because the Task Force did not have recent real-world evidence to corroborate their assertions, this was agreed to be an area for further analysis. The Task Force agreed that more quantitative analysis would be desirable but short timeframes and the complexity of the analysis required did not make this possible.

Distributional effects of charging Balancing Services charges on Final Demand only

The Task Force recognised that changing the BSUoS charging base to a smaller cohort would have additional distributional effects. Balancing Services expenditure is determined almost completely independently of who pays for it so reducing the size of the paying group will increase the burden on each individual. This means that BSUoS payees (suppliers) would face increased credit obligations with the ESO and greater commercial risks when setting tariff prices for their customers.

There will be a counterweight to the increased credit and commercial risks. Wholesale prices will fall, as generators do not include BSUoS in their pricing, creating lower credit requirements for suppliers buying energy in the wholesale market.

Some customers, particularly intensive energy users, are on BSUoS pass through contracts. Therefore, the Task Force recognised that some distributional effects may be felt by them too. However, under TCR principles, Suppliers are considered to act as a proxy for customers' interests and therefore it would not be reasonable to assume that only customers on pass through contracts would be detrimentally affected.

Consultation Feedback

One consultation response noted that a caveat to their support of the Task Force's recommendations on Deliverable 1 was that it would not be reasonable for suppliers to face a doubling in the BSUoS security requirement from NGESO and that security and credit requirements should be assessed holistically, considering all the changes to the BSUoS methodology.

The existing security arrangements in the CUSC[15] require suppliers to post security with the ESO equivalent to 32 days of total BSUoS charges and for generators to post security equivalent to 29 days of total BSUoS charges. If the charge remains as a £/MWh charge as the Task Force have recommended, then there is no immediate need to alter the security requirements for BSUoS. The ESO revenue team currently use the latest

[14] https://assets.publishing.service.gov.uk/media/576bcc3c40f0b66bda0000b4/appendix-9-12-the-cost-of-capital-fr.pdf
[15] CUSC 3.23.2 Determination of Security Requirement
https://www.nationalgrideso.com/document/91356/download

32 days of volume and charge data to hand at the ii or sf settlement runs depending on the day in question. The total value of 32 days' of BSUoS would be higher in general as average BSUoS prices will be higher with a smaller volume paying the charge. A major benefit of the move to a fixed charge would be that the amount required in security should be more predictable for suppliers as they are not subject to price fluctuations month on month. The only moving variable in this calculation will be the total volume supplied. Conversely, at the end of fix period the amount required in security will be subject to similar step changes in liability as the charge adapts to cover any mismatches in recovery from the previous period.

The Task Force explored a numerical example of potential changes to the credit cover requirements.

Credit cover increases, but not dramatically (28%), if BSUoS is fixed over 12 months, as shown in the summary table below. The results summarized below will vary under different assumptions, but this represents the most extreme cases of before vs after.

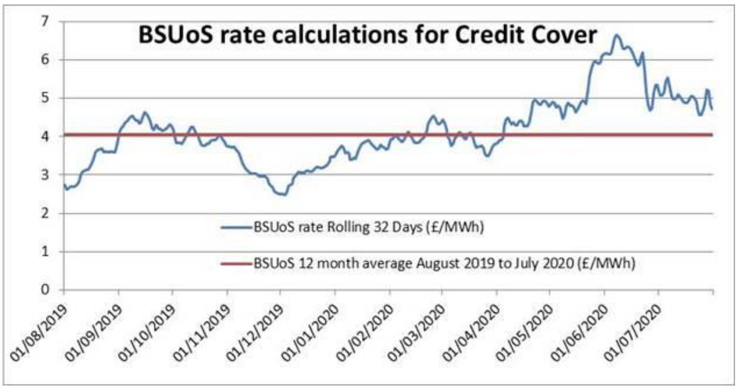
The assumptions can be changed[16], so the new credit rate will not vary so much from the old. This would lead to a smaller reduction in the credit rate and so the increase of credit cover required would become greater than 28%, with an upper threshold of 79% representing the full cost of BSUoS falling to suppliers with no change to the charging methodology.

In reality, because of the varying nature of businesses paying BSUoS and their differing approaches to managing this cost, there will be a range of different impacts across the market.

2019/20 BSUoS costs	
10	Illustrative Annual Supplier Volume (TWh)
0.141	Maximum Supplier BSUoS exposure (£m/day)
0.111	Average supplier BSUoS exposure (£m/day)

Regulatory impact on TAEV	
179%	BSUoS increase due to smaller chargeable volume

OLD CC	New CC (£m)	
32	29	Days to be covered
4.501	5.746	Supplier Credit Cover (£m)
	28%	Increase



The Task Force also noted that wholesale credit requirements for suppliers should fall so the overall security requirements on suppliers would be likely unchanged in the long run. Any changes to the BSUoS credit cover requirements should be considered as part of the CUSC modifications required to implement the Task Force's conclusions.

[16] Assumptions:
This example uses 12 months outturn BSUoS, from August 2019 to July 2020
A 12 month BSUoS price fix has been assumed
Example supplier has 10TWh TAEV as the volume of their portfolio, this represents circa 4% of total supply volume
The supplier may review Credit Cover annually
Supplier does not adjust their position throughout the year, but lodges a fixed amount of credit cover to cover any eventuality
Under the more stable ex ante pricing, supplier credit cover is put back to the default 29 days (10% risk premia removed)
The cost of BSUoS (unit rate) will increase by 79% due to removal of embedded benefits and generators no longer paying:
Current 10% Risk Premium is applied to Suppliers by extending the 29 days cover required to 32 days will be removed.
Current credit required will be 32 Days of the peak BSUoS rate x participant volume
New Credit required will be average annual rate x 29 days x participant volume x 1.79 (to account for regulatory change affecting TAEV

Task Force conclusion on Deliverable 1 and Next Steps

The Task Force recommends that Balancing Services Charges should be levied on Final Demand only

The key reasons behind the Task Force's conclusions are that:

1. Levying BSUoS charges onto Final Demand only will mitigate the existing distortions between GB transmission connected generators who are currently liable for BSUoS charges and interconnected and distributed generation who are not.
2. Expanding the charge base to include distributed generation would create a new distortion boundary between behind the meter generation and network connected generation and have a negative impact on the business case of new distributed and community generation which is overwhelmingly renewable or low carbon.
3. The first Task Force concluded that BSUoS should be a cost recovery charge, the addition of BSUoS related risk premia and transaction costs into both wholesale and retail prices is an inefficient method of cost recovery.

As per the Task Force's conclusions on Deliverable 2 there are strong arguments for changing the way in which balancing services costs are recovered and these changes mitigated some of the impacts the Task Force explored when considering levying BSUoS as is onto "Final Demand" only. Fixing BSUoS for a given period would remove or substantially reduce some of the potentially negative distributional impacts relating to increased credit requirements and the commercial risk of pricing BSUoS correctly into competitive tariffs. The benefits of removing harmful distortions on the generation side, however, would remain. As a result of this the Task Force concluded that balancing services charges should be paid by Final Demand only via suppliers.

Notice to industry prior to implementation was a key focus for the Task Force as such the Task Force recommend that two years' notice from the point of Ofgem's response to the Task Force's recommendation is given, , this notice period would include notice of the fixed charge such that tariffs begin on 1st April (the start of the charging year) two years after Ofgem's response .The Task Force also noted that it's important that Ofgem's response gives clear indication on the future BSUoS arrangements to make sure that this notice allows industry parties to successfully plan in the changes.

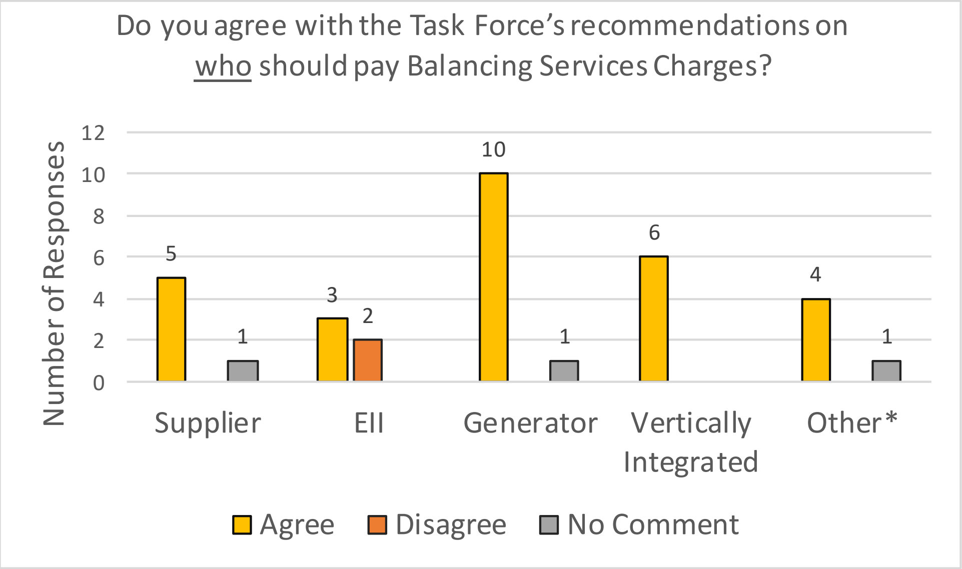
Acknowledging the uncertainty around the short-term consumer impacts, the Task Force also recommends that a quantitative assessment of consumer impact should inform Ofgem's final decision on these reforms. The Task Force has been unable to complete such analysis largely due to the sensitive commercial data required on supplier risk premia assumptions and costs of financing. Analytical modelling could robustly test the Task Force's principle-based conclusions and help to ensure that a decision is made that drives positive consumer and market outcomes.

The Task Force recommendation on Deliverable 1 will be reviewed by Ofgem to decide whether it should be implemented and what the implementation process will look like.

Consultation Feedback

The first question on the consultation asked respondents whether they agreed with the Task Force's preliminary conclusions that final demand should pay all Balancing Services charges.

1. Do you agree with the Task Force's recommendations on who should pay Balancing Services Charges (Deliverable 1)? Please state your reasoning and evidence behind your answer.



A large majority of consultation responses agreed with the Task Force's recommendation that Final Demand only should pay BSUoS. 28 of the non-confidential responses supported the view that Final Demand only should pay BSUoS.

Ignoring responses which offered no comment, **93%** of respondents agreed with the Task Force's initial conclusions that Final Demand only should pay BSUoS.

Several responses raised concerns that if the anticipated reductions in the wholesale price did not materialise consumers would be overall negatively impacted by the Task Force's conclusions. The Task Force acknowledged the findings of the 2016 CMA report into the competitiveness of the generation and retail sides of the GB electricity market which determined that generators do not have unilateral market power[18]. This finding implies that price competition in the wholesale market will, following a removal of BSUoS costs from generators, lead to a reduction in average prices. Several consultation respondents noted this in their responses and supported this view that the competitive wholesale market conditions would ensure pass through of BSUoS savings.

Four respondents suggested that Ofgem should monitor the wholesale price to ensure that savings to generators as a result of not paying BSUoS are passed through. The Task Force noted that Ofgem do closely monitor wholesale prices today and this would not be expected to change with the changes recommended by the Task Force. It was agreed that whilst it would be useful to be able to quantify the pass through of BSUoS savings through the wholesale price, in practice it would be impossible to isolate the effect of a change in the BSUoS methodology as there are many components of the wholesale price subject to a range of market influences. The Task Force also commented that BSUoS savings may be passed through in other markets e.g. as a price depressing influence on capacity market clearing prices. The Task Force recommends that a complete Impact Assessment is undertaken to better understand these market interactions.

[*] The "Other" category includes responses from Trade Bodies, Developers, the System Operator and ELEXON that don't fit well into the categories labelled in the graph.

[18] https://assets.publishing.service.gov.uk/media/576c23e4ed915d622c000087/Energy-final-report-summary.pdf paragraph 38

Deliverable 2: How should the charge be recovered?

2. How should Balancing Services costs be recovered?

The First Task Force concluded that it was not feasible to charge any of the elements of the BSUoS charge on a forward-looking basis to positively influence behaviour; thereby reducing the overall cost to end consumers.

This conclusion has prompted Ofgem to review how the costs are recovered.

To tackle this deliverable the Task Force considered example methodologies which were then assessed against the TCR principles. These methodologies fell broadly into two camps: a volumetric charge based on metered demand and a site-based charge, along similar lines to the Transmission Demand Residual (TDR) charging methodology as directed by Ofgem in its TCR Decision.

Potential for Change in How Balancing Services Charges are Levied

The Task Force were aware of the potential for the current £/MWh charge to send unhelpful signals as per the conclusions of the First Task Force.

Alongside this, there were two broad themes which the Task Force agreed were desirable attributes for change: reducing uncertainty and minimising industry financing costs.

a) Businesses struggle with uncertainty as it adds to cost and makes it more difficult to plan. A known charge can be factored into pricing plans accurately and does not attract a "risk premia" as the payee has confidence that the charge will not change. The consensus amongst Task Force members was that a 6-month fixed period was the minimum required for suppliers to begin to unlock the benefits associated with increased certainty. The ESO should be able to manage BSUoS risk more cheaply compared with suppliers or customers because the ESO could be given the regulatory authority to recover cash-flow shortfalls from suppliers, but by contrast, suppliers and customers would have to absorb unexpected BSUoS costs into their P&L.

b) Minimising industry financing costs should reduce costs to consumers as the financing costs won't be passed through prices and tariffs. The ESO should be able to borrow money to cover payments to service providers if a fixed balancing services charge doesn't cover the costs incurred or industry parties may borrow money to pay an unexpectedly high BSUoS bill. In both of these situations a financing cost is incurred and eventually is passed through to the end consumer under the assumption that the ESO would be able to fully recover its costs.

Consultation Feedback

Several respondents from different parts of industry questioned whether a revamped BSUoS charging methodology could be used to send signals. A key theme was a concern that a volumetric BSUoS charge levied on Final Demand could discourage power consumption and that could have a particularly negative impact on total system balancing costs during periods of low system demand.

The Task Force were concerned that any attempt to introduce a signal to the BSUoS methodology would contradict the conclusions of the first Task Force that BSUoS should be treated as a cost recovery charge and potentially introduce new unintended harmful distortions. Constructing the charge in a way which sends a signal also poses a revenue recovery risk for the ESO; it would be difficult to ensure a valid behavioural signal is sent to market parties which encourages them to act in ways which support a whole system approach, whilst also avoiding extreme under-recovery of BSUoS.

A Volumetric (£/MWh) Charge vs a Network Residual Style "per Site" Charge (£/site)

BSUoS is currently levied as a volumetric charge (£/MWh). There was a discussion within the Task Force about whether the charge should remain as a volumetric charge or whether a per site charge, should be introduced which would align with the approach chosen by Ofgem for the purposes of recovering network Residual charges.

From April 2022, network residual charges (the Transmission Demand Residual (TDR) and DUoS Demand Residual (DDR)) which recover some of the Transmission Owner and Distribution Network Owner revenues, will be recovered from Final Demand Sites through a "banding" methodology. There will be a set of four charging bands for non-domestic customers at each voltage level: LV (no MIC), LV (MIC), HV and EHV. As well as a single nationwide band for all domestic connections. Transmission connected Final Demand Customers will also pay the TDR levy on a £/site basis, but it is not yet determined how many Transmission Charging Bands will be created.

A single nationwide Transmission Residual tariff will be created for each Charging Band. A single Distribution Residual tariff per DNO area will be created for each Charging Band. Final Demand Sites are allocated to a Charging Band and remain in that band for the duration of the onshore Transmission Owner price control. They will pay the Residual tariff according to their band.

The purpose of these changes is to ensure that the TDR and DDR, as “cost-recovery” charges, are unavoidable and do not send behavioural signals to industry parties.

The First Balancing Services Task Force concluded that BSUoS charges were cost recovery charges. Therefore, it was a natural step for the Task Force to consider a charging methodology for recovery of BSUoS charges that aligned with the methodology for TDR/DDR charging.

Whilst the Task Force could see the logic in utilising TDR bandings in BSUoS charging, there was a significant concern that the banding methodology proposed by the TDR may not be appropriate for BSUoS. The TDR bands are fixed for the duration of a price control and, notwithstanding a dispute or intervention, sites stay in the same band for the duration as well. Allowing more frequent re-banding to take place, capturing changes in the site’s operation, could be beneficial but at the expense of additional complexity.

Alongside these concerns, The Task Force recognised several shortcomings with the TDR banding approach many of which are captured in the assessment table below.

The Task Force assessed the merits of the volumetric methodology and TDR banded per site methodology against the TCR principles, the Task Force did not consider alterations to a banding methodology (like re-banding every year or using consumption rather than capacity to band) in this pros and cons exercise.

TCR Principles	Fixed Volumetric Charges (£/MWh)	Fixed Banded per Site Charges (£/site/day)	Pros/Cons
Reducing Harmful Distortions	Flat volumetric charge would reduce harmful Time of Day distortion Reduced Behavioural Signalling	Harder to Avoid than a volumetric charge, so Reduces Inefficient Avoidance Action No Behavioural Signalling	Positives
	Encourages potentially “out of merit” BtM generation	Charging Bands can Create Distortions	Negatives
Fairness	Energy Services should be billed in relation to Energy Volume	Benefit from a Stable System whether small or large user Reduces Incentives for Partial Grid Defection	Positives
	Some Users Find it Easier to Avoid Than Others	Grid Defection Impacts All Remaining Users Impact on those in fuel poverty	Negatives
Practicality and Proportionality	Frameworks Exist for Easy Implementation Simpler than Banding Approach Low distributional impact on end consumers as maintains status quo	Frameworks Exist for Easy Implementation contingent on Final Demand only paying	Positives
		Risk of Overloading Industry Parties	Negatives

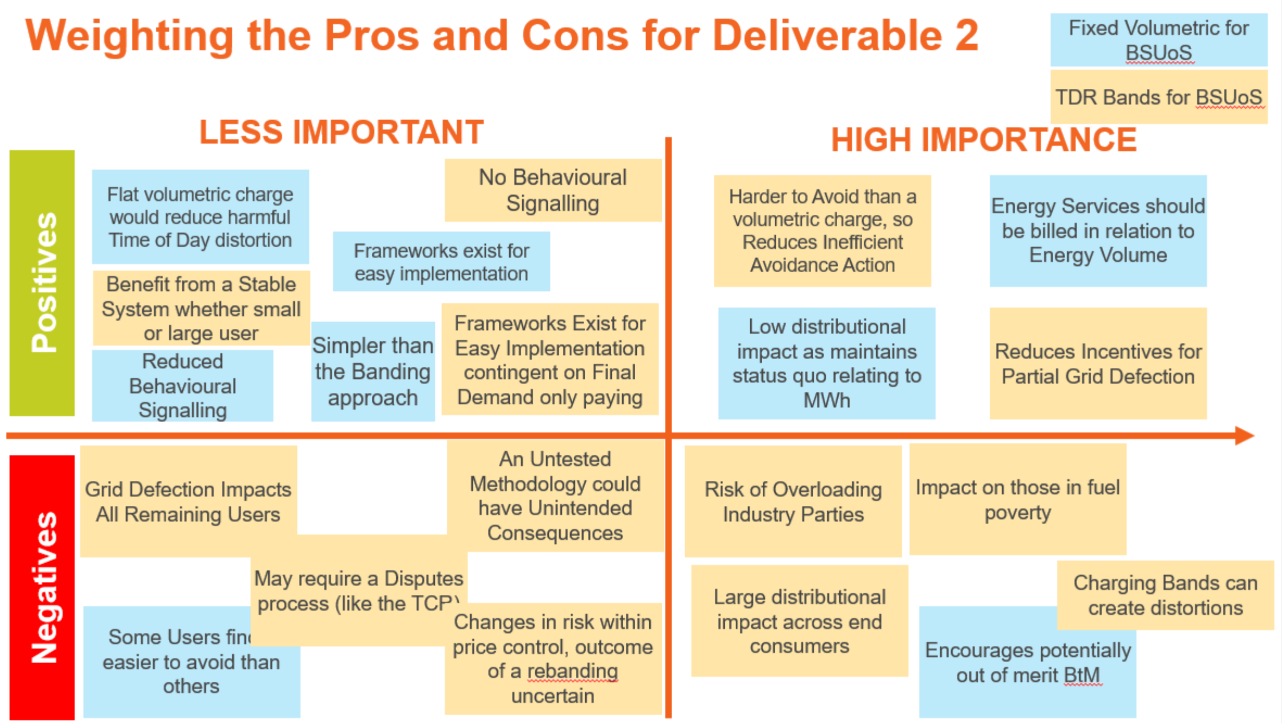
	An Untested Methodology could have Unintended Consequences **May require a Disputes process (like the TCR)** **Large distributional impact across end consumers**	

Term	Explanation
Risk of Overloading Industry Parties	Per site charges are exposing certain industry parties to higher costs which they previously took action to avoid. The Task Force were concerned that adding more costs, levied in the same manner, to these parties would create such a huge cost burden that they may collapse. This is a particular concern for energy intensive users operating in international markets where their competitors don't face the same network charges.
Harder to Avoid than a volumetric charge	The TCR has determined that cost recovery charges should be unavoidable and not send any behavioural signals to industry parties. A banded, per site charge is unavoidable unless the site goes completely "off-grid". Partial grid defection can lead to economically inefficient generation to avoid network charges.
No Behavioural Signalling	The TCR has determined that cost recovery charges should be unavoidable and not send any behavioural signals to industry parties. A banded, per site charge won't send signals to industry parties to alter their consumption patterns. There may be a good reason to try and signal to users to alter their offtake, notably over summer, as that would reduce balancing costs to all customers, although it would be more efficient to provide this signal via ancillary services contracts and the Balancing Mechanism.
Equal Benefit from a Stable System	Balancing Services Charges recover costs expended in ensuring stable and secure system operation. All connections benefit equally from these system features whether they are large or small volume users, therefore, the charge should not be based on consumption/export volume.
Some Users Find it Easier to Avoid Than Others	Reducing energy consumption by reducing load or installing behind the meter generation will reduce the overall Balancing Services Charges bill if a volumetric approach to charging is taken. Some users will find it easier than others to avoid this charge but as with the "Equal Benefit" point retain the same benefit.
Grid Defection Impacts All Remaining Users	Complete "Grid Defection", where a user completely gives up their connection, which would be incentivised if a customer could self-supply their own energy, capacity and security cheaper than sourcing this from the network. The Task Force agreed that this was difficult and expensive to achieve, so is quite unlikely, but could have a high impact on the system if it did occur. The impact is to increase revenue recovery charges for all remaining users which is an undesirable outcome.
Reduces incentives for partial grid defection	"Partial grid defection" occurs where a customer can source some, or all of their energy requirements from self-supply, but they retain a network connection as a backup. Fixed charges reduce the incentive for partial grid defection compared with volumetric charges preventing costs landing disproportionately on those least able to avoid them.
Encourages Carbon Intensive BtM generation	Revenue collection levies applied on a £/MWh commodity create a distortion which incentivises BtM generation to dispatch out of economic merit. Most behind the meter generation that is installed to protect the site from volumetric peak charges will be carbon intensive. Small diesel and gas generators with limited running times[19] are subject to less

[19] For fuel burning generators between 1 and 50MW operating more than 50 hours per year compliance with the Medium Combustion Plant Directive (MCPD) air quality standards is required by 2025. Large combustion plants had to meet these standards by 2015.

	stringent environmental regulations than larger plants. This move would work against the UK's decarbonisation objectives.
Frameworks Exist for Easy Implementation	As a result of the TCR, changes to the network residual charges system and process changes have been undertaken to enable both a volumetric and a banding methodology to be easily implemented. Neither would introduce a new methodology for industry to spend time understanding and managing.
Simpler than Banding Approach	The Task Force felt that the volumetric charge was simpler to understand and to implement than a banding approach.
An Untested Methodology could have Unintended Consequences	The banding approach has yet to be tested in a practical setting. There may be unintended consequences to this new way of charging which are yet to be encountered. The Balancing Services Charges bill would add into the mix between £1.5-3billion more per year to recover using this methodology. The impact of the unintended consequences would be more severe with higher costs involved.
Charging Bands can create distortions	Distortions are found either side of a band boundary where relatively similar users are paying different fixed charges and relatively different users within a band are paying the same charges.
Energy Services should be billed in relation to Energy Volume	The Task Force felt that Balancing Services charges were specifically related to energy services rather than asset infrastructure cost (like network TNUoS/DUoS charges) and as such should be billed in relation to energy volumes. This way those that consumed more energy would pay more in Balancing Services charges than those that consumed less.

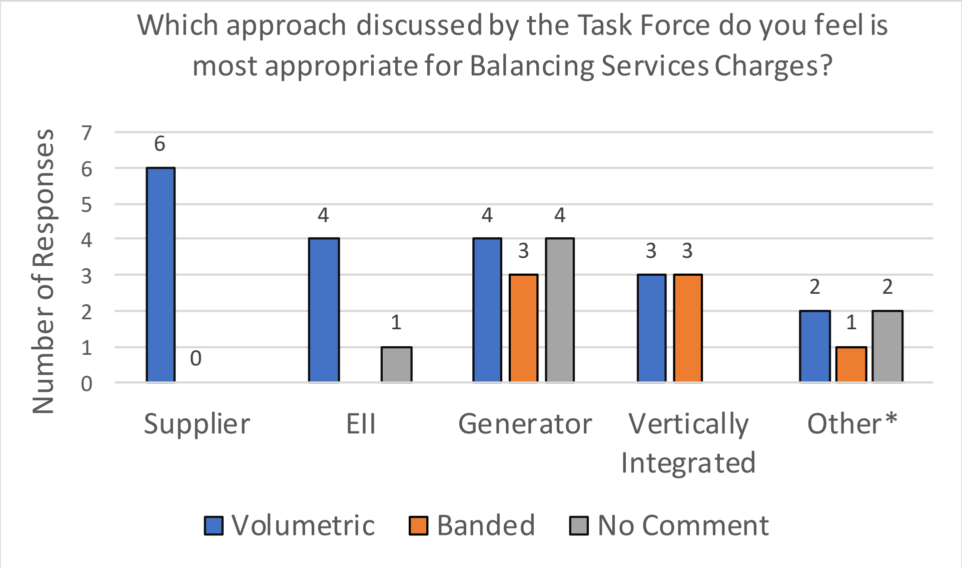
The Task Force sought to segment their pros and cons into two categories: High Importance and Less Important. The below graphic shows the outcome of this exercise with the more important considerations to the right-hand side. This exercise supported the Task Force in coming to their final recommendation that a volumetric charge was more appropriate for BSUoS charging.



Consultation Feedback

Question 5 on the consultation asked respondents which of the volumetric and TDR banding methodologies was preferable for charging BSUoS.

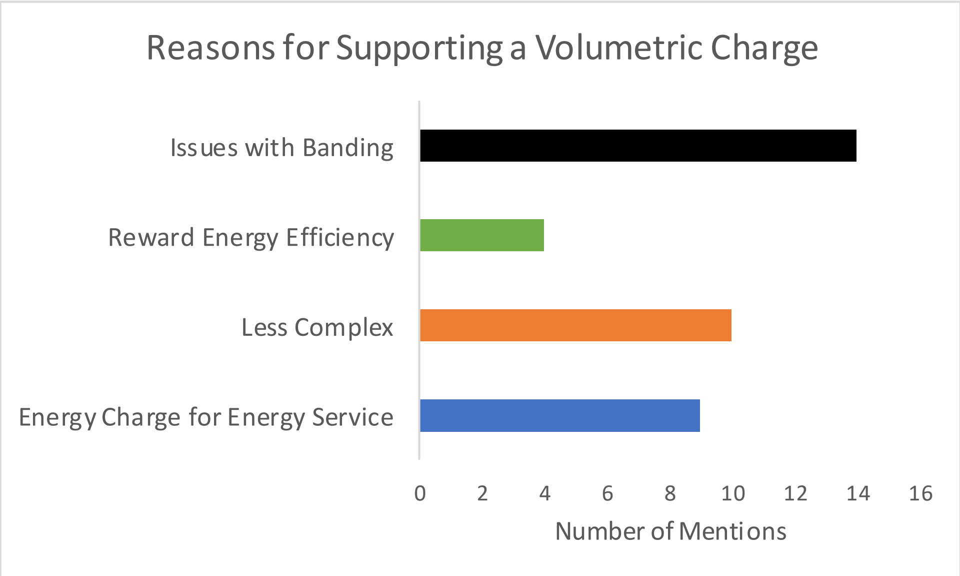
5. Which approach discussed by the Task Force (TDR banded £/site/day or volumetric £/MWh) do you feel is most appropriate for Balancing Services Charges? Please consider your answer against the TCR principles and state your reasoning and evidence to support your answer.



Out of the 33 non confidential responses 19 responses reported a preference for a volumetric approach to BSUoS charging.

Ignoring responses which offered no comment, **73%** of respondents believed that a volumetric charge was the most appropriate option for BSUoS charging.

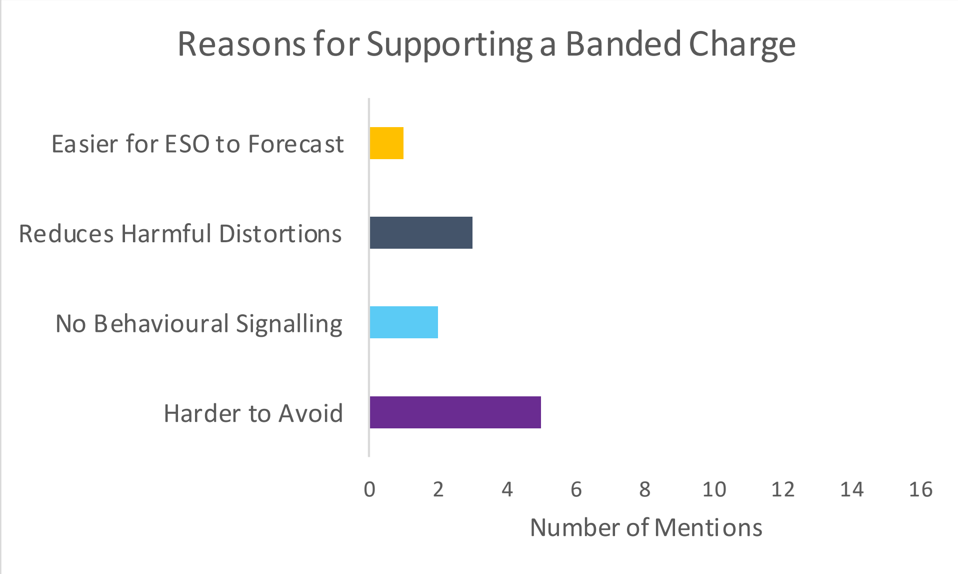
The most common reasons for supporting a volumetric approach were:



Out of the 33 non confidential responses 7 responses reported a preference for a banded approach to BSUoS charging.

Ignoring responses which offered no comment, **27%** of respondents believed that a banded charge was the most appropriate option for BSUoS charging.

The most common reasons for supporting a banded approach were:



ELEXON joined the Task Force's 8th meeting on 9th September 2020 to discuss their response to the Task Force consultation with respect to their commentary about in flight BSC modification P375[20]. P375 aims to introduce the option to settle BMUs using metering equipment located behind the boundary point rather than using the metering at the boundary point as is currently mandated through the BSC. P375 is currently only focusing on the option to independently settle "behind the meter" assets for the purpose of balancing services provision. However, the P375 solution could be extended in the future to other forms of settlement after following the appropriate code change process.

The Task Force raised concerns that due to the current voluntary nature of the proposals under P375 a "behind the meter" metering option could be circumvented by sites if commercially advantageous. This would not in itself solve the main drawback of the volumetric approach (in that it can be avoided by parties with behind the meter generation). At this point the Task Force felt that a mandatory roll out of the P375 solution would not be a practical and proportionate mitigation for the identified avoidance issue but recognised that this concern could fall away in the future.

Alternative Options for a Banded BSUoS Methodology

Consultation Feedback

A small number of responses raised a concern with the five-year duration of the TDR/DDR charging bands being unsuitable for managing changes in site usage. Others cited the creation of "cliff edges" in charges between bands creating unfair outcomes or competitive distortions within EII sectors.

The Task Force explored how an alternative banding methodology could reduce some of the problems associated with a volumetric charge: most importantly the incentive to avoid the charge by utilising behind the meter generation.

A full table of potential pros and cons of an alternative banding approach is contained in the Appendices. Some potential ideas were put forward:

1) Further segmentation of domestic sites to protect households in fuel poverty and provide a less regressive charge.
2) Segmentation of Energy Intensive Industries (EIIs) to protect their international competitiveness.
3) More frequent re-banding to take into account changes in the sites' circumstances and usage of the system.

[20] https://www.elexon.co.uk/mod-proposal/p375/

Ultimately, the Task Force determined that the complexity introduced by a similar but different banding approach did not perform well against the practicality and proportionality principle for the potential benefits identified.

Example Fixed BSUoS Tariffs

The ESO created some example tariffs using the banding assumptions for the TDR/DDR bands published through the Charging Futures Forum in June 2020 and 2019/20 forecast BSUoS data. The outcome of the TCR CUSC and DCUSA modifications was not known at the time of submission for this report, as such there are still some unknown factors about how the banding could affect the tariffs. The impact of Deliverable 1 on the charge was to increase average BSUoS prices by 79%.

The differences between the banded and volumetric options (Deliverable 2) are explored in the two tables below: one the left hand side is a set of example tariffs using the TDR/DDR banded method, on the right hand side an example of a 12 month fixed charge set using the ESO's 2019/20 forecast from January 2019 (an example of a 2 month notice period).

2019/20 TDR Bands					TDR BSUoS Tariff
LV	Domestic			£	18.99
	LV no MIC (kWh)	-	4,248	£	9.21
		4,248	14,178	£	47.02
		14,178	28,836	£	110.13
		28,836	∞	£	328.47
	LV MIC (kVA)	-	82	£	682.98
		82	150	£	1,137.42
		150	230	£	1,766.67
		230	∞	£	3,972.08
HV	HV (kVA)	-	425	£	2,844.96
		425	1,000	£	9,851.07
		1,000	1,800	£	19,164.16
		1,800	∞	£	47,211.13
EHV	EHV (kVA)	-	4,000	£	16,575.19
		4,000	12,000	£	99,061.39
		12,000	20,000	£	211,170.29
		20,000	∞	£	567,873.63
Transmission-connected				£	478,977.62
Unmetered Supplies (p/kWh)					0.56

2019/20 Fixed Volumetric	
BSUoS Forecast	£ 1,469,520,000
Total Chargeable Volume	261,966,700
Forecast £/MWh Tariff	£ 5.61

Distributional Impacts

The Task Force wanted to explore the distributional impacts of the two shortlisted options for Deliverable 2. Annual volume data was gathered on a range of example sites in each of the charging bands. A breakdown of the data used, and the accompanying graphs, can be found in the "Distributional Impact Analysis" section. The Task Force's analysis showed that a TDR banded approach to BSUoS charging created significant distributional impacts on most Final Demand sites as the charge was the most different from today's methodology. The potential for distributional impacts and "cliff edges" between bands was a key element of the Task Force's decision to recommend a volumetric approach over a banded approach.

Fixing Balancing Services Charges for a Set Period

The Task Force explored options for fixing Balancing Services charges ahead of time. This is a major change from the current methodology where there is a new £/MWh charge calculated for every half hour settlement period on an ex-post basis.

The Task Force agreed that it was difficult to identify a point of maximum benefit for the industry as a whole. Broadly, suppliers were assumed to prefer longer fixed periods with significant notice period to remove the uncertainty around Balancing Services Charges bills. This would allow them to offer some supply contracts to customers with no "risk premia" related to Balancing Services Charges. The ESO, on the other hand, would be likely to over or under recover Balancing Services revenue by a larger margin the further away from "real-time" the tariffs are set. This would lead to potential risks for the ESO financial position and create a temporal dissonance as costs from some time before are recovered through a "K factor" adjustment.

Over or under-recovery of TNUoS revenue is currently made during the financial year two years later than the year in which the over or under-recovery took place. This recovery period could be utilised for correction of over or under-recovery of a fixed BSUoS charge or a different recovery period could be dictated by Ofgem if it added more consumer benefit.

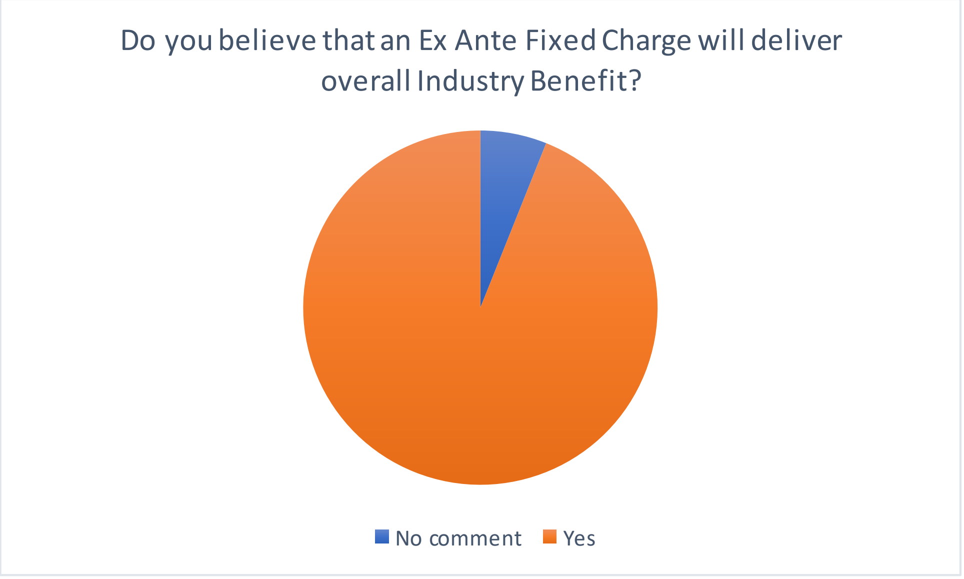
Consultation Feedback

Question 3 on the consultation asked respondents whether they believed an ex ante fixed charge would deliver overall industry benefits.

3. Do you agree with the Task Force's recommendations that an ex ante fixed charge would deliver overall industry benefits? Please state your reasoning and evidence behind your answer.

31 responses agreed that an ex ante fixed charge would deliver overall industry benefits.

Ignoring responses which offered no comment, **100%** of respondents believed that a fixed BSUoS charge would deliver overall industry benefits.



Respondents agreed with the Task Force's views that overall industry benefit could only be determined by comparing the increase in ESO financing and risk bearing costs with the value of risk removed from industry parties. Whilst this hypothesis has not been quantitatively assessed by the Task Force, many respondents believed that in principle overall industry benefits would be delivered by a fixed charge.

Several respondents noted that, as currently levied, BSUoS represents a volatile and unpredictable P&L impact and is a substantial, unnecessary source of risk for suppliers and those customers on BSUoS pass through contracts.

Impact on Suppliers of an Ex Ante Fixed Charge

There was widespread agreement that fixing charges would provide a much greater degree of certainty over the Balancing Services Charges bill that suppliers will expect to face for the duration of the fixed period. This would benefit customers as supply tariffs could be created that accurately reflect the Balancing Services bill and a risk margin would not need to be factored in. The Supplier price cap may also be easier for Ofgem to set as there would be greater certainty over the Balancing Services charges component of a consumer's bill.

The length of the fixed period was a key topic of discussion. If contracted periods cover more than one fixed period there will be a change in the charge part way through a contracted period which Suppliers would have to manage in their agreements with customers. This led to a discussion on a related topic: that of the notice period in which industry parties would be informed of the Balancing Services tariff prior to the start of the fixed period.

Consultation Feedback

Question 9 on the consultation asked respondents whether there were interactions with the Supplier Price Cap that needed to be considered by the Task Force.

9. Do you feel that there any interactions with the Supplier Price Cap that need to be considered? Please state your reasoning and evidence behind your answer.

Many respondents offered no further comment on this question. Some argued that given an ex ante fixed BSUoS charge the cap would be easier to set. A small number of responses drew the Task Force's attention to the fact that balancing charges will continue to form part of the 'policy and network costs' allowance in the price cap. To enable the most efficient setting of the price cap the notice and fixed periods for the fixed BSUoS charge should align with the price cap periods (April – September and October – March). Ofgem announce the level of the cap on the 5th working day of the month, two months prior to the start of the cap (5th working day in February and August).

The Task Force noted this comment and considered it when forming their recommendation on notice and fixed periods.

Another response raised the point that the current "lagged pass through" approach to the price cap methodology would not be appropriate in combination with the Task Force's proposed recommendations (an ex-ante charge recovered from final demand). As it stands, under the current price cap methodology, the impact of a new and much higher average BSUoS cost would not be fully included in the domestic price cap for 18 months post implementation. This creates a risk for suppliers that they will be unable to adequately fund increased BSUoS costs. Setting BSUoS ex-ante would also create a transitional impact as the cost true up for cap periods before the move to an ex-ante approach would also need to be factored into allowances. The Task Force recommend that Ofgem should include the new fixed BSUoS price in the price cap from the point of implementation, including any necessary adjustment to true up allowances for cap periods before the move to an ex-ante approach.

No further interactions between the Task Force's work and the supplier price cap were identified.

Impact on the ESO of an Ex Ante Fixed Charge

Balancing Services Charges revenue enables the ESO to fund the costs incurred from balancing the system. If under-recovering this revenue, the ESO (like all companies in such a position) would borrow to finance the shortfall. The Task Force expected that the ESO would have recourse to comparatively cheaper costs of borrowing compared to some industry parties, providing the ability to recover the shortfall at a later date was covered in the regulatory framework.

The ESO finance team confirmed that under-recovery of BSUoS must be reported as a loss on the group P&L reporting. A statement from the ESO Technical Finance team explained that:

"An entity is subject to rate-regulation where it is party to a framework for establishing the prices that can be charged to customers for goods or services and that framework is subject to oversight and/or approval by a rate regulator.

For such entities, where an amount of income or expense is included, or is expected to be included, by a rate regulator in establishing the price(s) that an entity can charge to customers, this is referred to as a rate-regulated activity. Such activity cannot (currently) be recognised under the IFRS framework (unless an entity is able to apply IFRS 14: Regulatory Deferral Accounts; the entity has to be a first-time adopter of IFRSs in order to apply this standard) as it does not meet the framework's definition of an asset or liability."

This means that, as the ESO did not initially choose to apply IFRS 14 deferrals when first adopting IFRS financial reporting, under-recovery of BSUoS is not compensated for in that year's final accounts by the prospect to recover it through "K-Factor". Essentially, the fact that ESO revenue is overseen by a regulator means that the IFRS template considers there to be uncertainty around the revenue as decisions around regulatory recovery could be reversed or subject to legal challenge.

This causes concern for ESO as it impacts National Grid Group shareholder dividends for that year despite the assurance of being able to make up the under-recovery through a "K-Factor" at a later date. Ofgem's finance team confirmed that typically a "K-Factor" adjustment to correct for over or under recovery has approximately a two-year delay from the time of over or under recovery.

NGESO's View: A Cap on Under-Recovery

The ESO is a standalone legal entity with a relatively small asset base. This makes raising finance more difficult than for asset heavy businesses such as networks. The scale of the current borrowing facilities for the ESO are only possible through implied support from the ultimate parent company. Whilst the shareholder may be willing to underpin the facilities required to provide a modest level of support to BSUoS tariff fixing, they could not be expected to support an uncapped liability with potentially significant impacts to group liquidity and short-term earnings.

An Ex Ante Fixed Charge could only be supported by the ESO under two conditions:

> **Condition 1** - there must be a cap on the ESO's BSUoS liability (under-recovery of BSUoS revenue in relation to balancing services expenditure). An uncapped liability is not financially viable for any business in any circumstance.
>
> **Condition 2 –** The cap should be proportionate to the financial standing of the ESO as an independent and legally separate entity from the National Grid group. The ESO does not have the balance sheet strength or financeability for an increase in its current credit facilities and Ofgem have removed the risk related to tariff setting for TNUoS revenue recovery, through a "pay when invoiced" approach for RIIO2 for this reason.

If ESO credit facilities are in place for a capped BSUoS liability this must not impact the credit rating of the ESO, whether the facility is drawn upon or not. This must cover all possible scenarios including cash flow risks from other sources

Without these conditions in place an uncapped liability for highly volatile balancing services expenditure recovered through an ex ante fixed charge will have a downward pressure on NGESO's (and potentially NG Group's) credit rating due to the high-risk cash flow position it will create. The ESO see this as an unavoidable impact of an uncapped BSUoS liability.

Although there would be a regulatory guarantee of recovery, other considerations would still impact on the credit rating such as NGESO's ability to service its debts. NG Group as a 95% regulated entity could be expected to hold a AAA credit rating, however it is currently rated Baa1/BBB+ this shows that a regulatory guarantee of liability recovery is not the only influencing factor on an organisations' credit rating.

Any impact on credit rating will directly feed through into an increase in expense to fund this liability. Ultimately, as the risk of lending to the ESO increases there may come a point where the ESO is considered too risky for the potential returns on offer.

The ESO has not determined the exact value of a proposed cap on shortfall; the CUSC modification CMP350 introduced a £100m cap on COVID support on BSUoS from the ESO and so this seems a reasonable starting point. The ESO proposes that this cap should be in place for within year shortfalls rather than viewed over the whole of a fixed period which may be a charging year. This will enable the ESO to set up a borrowing mechanism to account for BSUoS shortfalls at a reasonable price for consumers. The ESO expects that the cap should be reviewed on a regular basis to make sure it is functioning properly and providing value for consumers. A cap could be a trigger to calculate new BSUoS tariffs for the remainder of the fixed period or trigger an automatic and signposted change to the tariff (either increasing or decreasing by an set amount known in advance). We are open to exploring any solutions which might manage this risk in the interests of ESO, industry and consumers.

Any cap on ESO exposure to funding BSUoS tariff fixing, would need to be considered on a rolling monthly basis to ensure the ESO could manage liquidity at all times. Hence a cap within a specific charging period would need to take into account any over or under recovery from prior periods until such time as excesses or shortfalls were recovered through future charges.

It is also important to consider that any shortfall in collecting BSUoS revenues would directly impact the profit of the ESO, a business that can expect to earn a profit after tax of around £6m pa in RIIO2. A sustained period of under recovery in RIIO2 would prohibit making a payment of a return to shareholders in a period where the shareholder is expected to inject additional equity to support the funding of significant increased capital investment.

Task Force Views

The Task Force were not in favour of any cap on under-recovery. A cap creates uncertainty and removes any benefits of a fixed charge. The Task Force ultimately did not believe that the ESO's assertion that BSUoS risk could not be financed at an acceptable cost to consumers was valid. The cost of managing the volatility of BSUoS is ultimately paid for by consumers and the Task Force believe that this cost will be lower if it is managed by a party with a regulatory guarantee of recovery, compared to if it is managed by parties with no such regulatory guarantee.

The Task Force concluded if such a financing problem did exist alternative solutions to support the potentially extreme under-recovery could be:

1) The Task Force enquired about the possibility for a third entity (outside of the ESO and National Grid Group) managing the cash flow risk.
2) Another option was whether a transparent "risk premia" i.e. £0.10/MWh added into the fixed BSUoS price calculated through the new CUSC methodology could be included in the fixed price to reduce the possibility of under-recovery. The expected over-recovery at the end of the fixed period could then be redistributed back to those liable for BSUoS through future tariff setting. This alternative would need to be robustly assessed against the ESO cost of financing to ensure that the solution delivered overall benefit to end consumers. It was also not yet possible to determine how much this uplift would need to be to reduce the risk to an acceptable level for the ESO.
3) National Grid Group should manage this risk on behalf of the ESO as its parent company and no mitigation measures are required from wider industry or consumers. This raised questions over the usefulness of legal separation of the ESO from the wider group in terms of delivering the Task Force's solution of a fixed BSUoS charge.

If a cap was deemed to be the best solution to tackle extreme mismatches in recovery the appropriate safeguards would need to be in place. If a cap was taken forward, industry should have a means to audit and challenge tariffs set by the ESO in advance of the start of a fixed period.

NGESO's View: Adequate Remuneration

As at draft determinations, the RIIO-2 framework does not have a clearly defined mechanism through which the ESO could assume additional BSUoS cash flow risk and how this would be funded. The ESO proposes that a transparent mechanism through which the ESO would be remunerated for the transfer of risk from other industry parties should be agreed with Ofgem alongside any code modification.

Task Force Views

The Task Force did not feel this was an unreasonable expectation but were mindful that the combined costs of ESO financing and remuneration must not outweigh the benefits from a reduction in risk premia or consumer value would be at risk.

NGESO's View: Timing

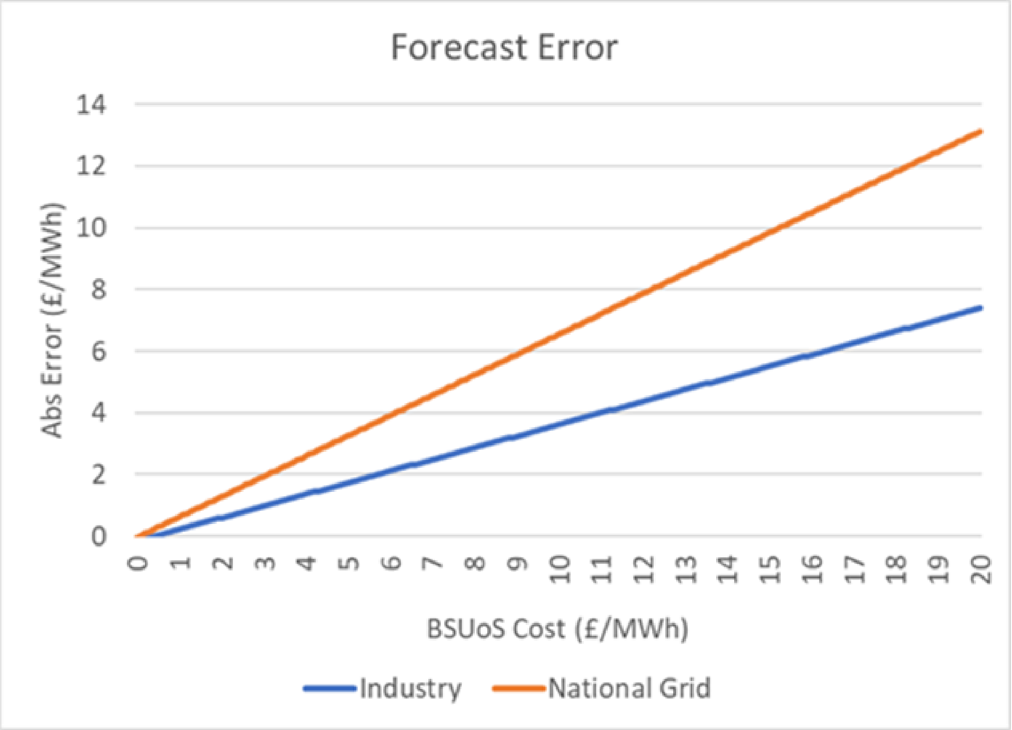
The ESO was concerned that decisions on code modifications to introduce the Task Force's recommendation could be made out of time with the necessary discussions on ESO financing. The ESO strongly believes that a more efficient and holistic solution will be found if these conversations and decisions happen in parallel.

Task Force Views

The Task Force agreed with the ESO's views that a holistic approach to detailed solution development and decision making would be beneficial.

BSUoS Forecasting Accuracy and Potential for Improvement

The Task Force discussed whether fixing the charge might incentivise the ESO to improve their BSUoS forecast accuracy. It was agreed that currently the forecast is not very accurate and has a greater absolute error than some comparable forecasts[21].



The Task Force compared the ESO BSUoS forecast accuracy with an alternative forecast produced by Catalyst Commodities. The Catalyst Commodities forecast has almost half the average error of the ESO forecast see graph above.

The ESO believe that it is important not to place pressure on control room engineers to "hit" forecasted spend costs for different instructions as this may impact their decision making required to ensure safe and secure system operation. The ESO also noted that under the BSIS scheme the modelling used to determine the "optimal spend" was outperformed by Control Room engineers on a consistent basis. This was due to an engineer's ability to use experience and advice to mitigate the cost impact of simultaneous actions in many parts of the network which were too complex for the model (PLEXOS). Ofgem's regulatory finance team noted that changes to the recovery of costs through BSUoS charges may require additional financing measures. However, the Task Force ultimately believed that fixing the charge would result in an improved accuracy in forecasting from the ESO and therefore have a lower impact than might otherwise be felt. In principle, this conclusion appears valid but requires further operational expenditure allowance for the ESO to allow it to effectively forecast and manage the cost base of the external factors that influence the BSUoS charge in addition to its system balancing role.

Consultation Feedback

One consultation response identified an expected benefit to industry of the ESO producing a three year ahead forecast of BSUoS prices. This would support suppliers in tariff setting for their one, two- and three-year fixed

[21] https://www.catalystcommodities.co.uk/

price contracts. The Task Force agreed that transparency over costs and tariff setting is important for industry and helps to facilitate more efficient markets.

How long should the Fixed Period be and How much Notice should be given to Industry?

Some examples discussed by the Task Force are contained in the table below. They lean on a 6-month or 12-month fixed period with a 2 – 12 months' notice period. The dates given in the right-hand column align with the popular contracting windows of April and October. The 9 months' notice option is given for the 6-month fixes only as it enables a supplier to have certainty over the BSUoS price for the entire duration of a 12-month contract despite a step change in the tariff part way through the term. These options would all also provide a level of certainty on the BSUoS component of their charge to customers on BSUoS pass through contracts. Consumers of all sizes would benefit from reduced risk premia being added into their contracts and most options would enable suppliers to offer a 12-month fixed term contract with full certainty over the BSUoS price.

Notice Period	Length of Fixed Period	Dates
2 months	6 months*	BSUoS Tariff published 1st February 2023 Effective from 1st April 2023 until 30th September 2023
9 months	6 months*	BSUoS Tariff published 1st February 2023 Effective from 1st October 2023 until 31st March 2024
12 months	6 months*	BSUoS Tariff published 1st April 2022 Effective from 1st April 2023 until 30th September 2023
2 months	12 months	BSUoS Tariff published 1st February 2023 Effective from 1st April 2023 until 31st March 2024
6 months	12 months	BSUoS Tariff published 1st February 2023 Effective from 1st August 2023 until 31st July 2024

*Note that for these options a second round of tariff publications and effective from dates would be required to complete a full year's tariffs and revenue collection. For simplicity, only one round is given as an example.

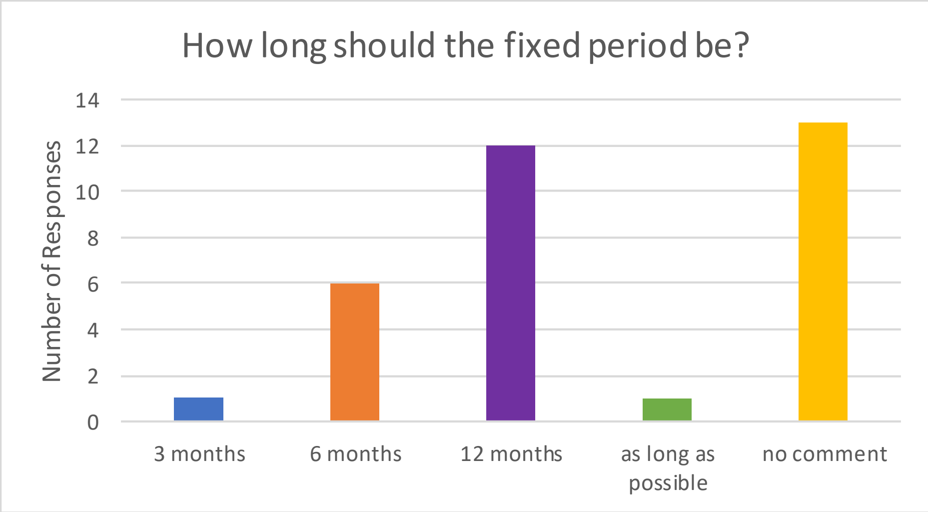
Consultation Feedback

Question 4 on the consultation asked respondents how long they believed the fixed period should be and what the optimal notice period was.

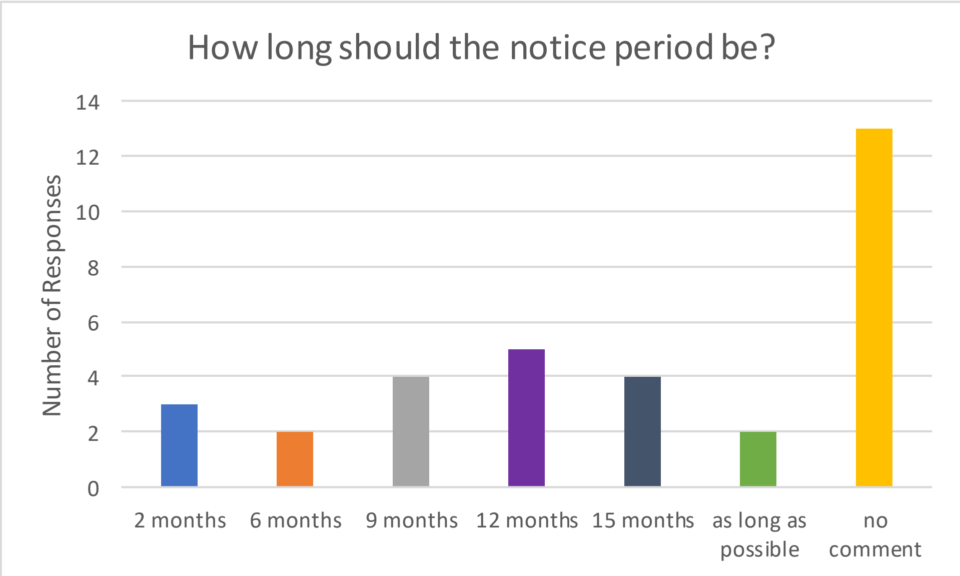
4. How long do you think the fixed period should be and what in your opinion is the optimal notice period in advance of the fixed charge coming into effect? Please state your reasoning and evidence behind your answer.

A range of responses were received to this consultation question. There was no one over-riding combination of fixed and notice periods that was preferred by the respondents.

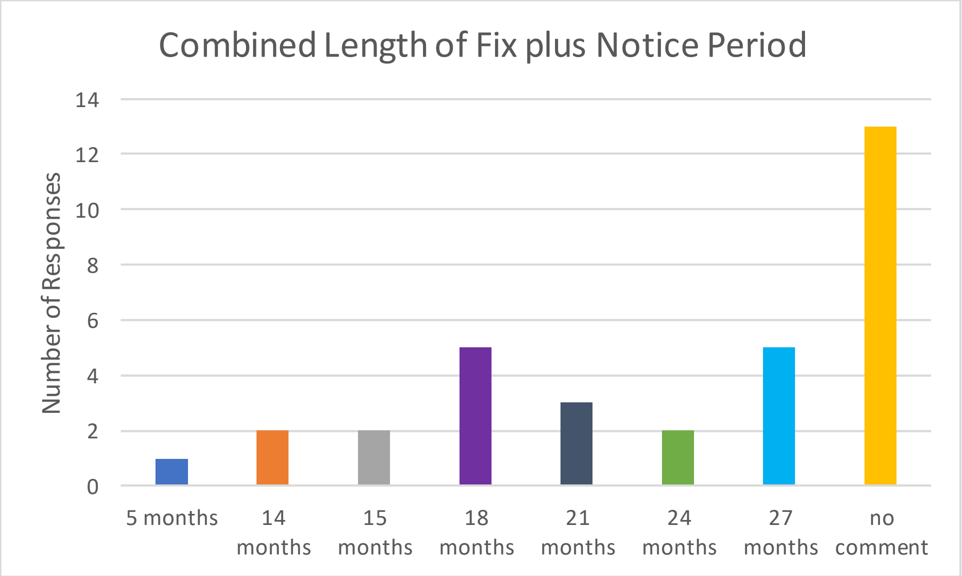
The most popular response (after no comment) was in support of a 12-month fixed period.



The main point of agreement amongst the respondents was that given the trade-off between supplier certainty and accurate forecasting horizons a longer notice period was more valuable than a longer fix period.



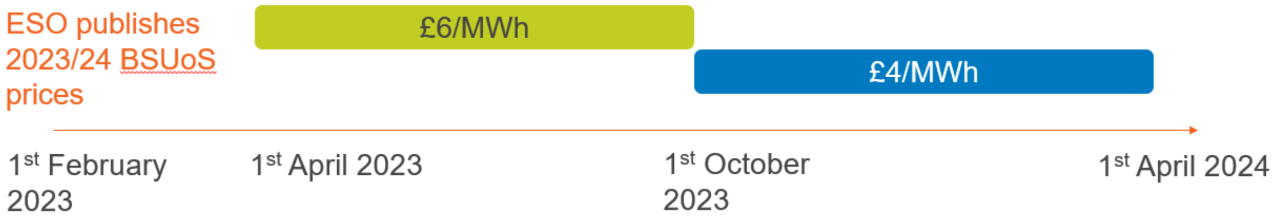
The Task Force also explored what the respondents' views were in terms of combined total fix and notice period. This was not explicitly asked of respondents in the consultation and so may not have been answered with this in mind but goes some way to show the spread of responses and the total time period suggested. For those respondents who opted for "as long as possible" in their response this was assumed to be equivalent to the maximum length suggested in answers to this question.



Further points raised in the response to Question 4 were:

1) That providing regular forecasts to industry would be beneficial and that more detailed proposals on updates to industry needed to be worked up and consulted on. The Task Force believed that more of this detail would be developed through the resulting CUSC modifications.
2) That price movements between periods should be capped to avoid big step increases.
3) Provisions for managing BSUoS risk could be captured in the ESO price control.

The ESO responded to Question 4 highlighting that the longer the combined notice and fix period was the greater the risk of under or over recovery. This will lead to more costs being incurred through the K factor and bigger step changes in prices fix period on fix period. The ESO suggested that a possibility for tariff setting would be to provide two or more prices within the same fixed period with notice given of all dates and prices in advance at the "notice period" stage (see example below).



The Task Force discussed this proposal and noted that a methodology like this would send weak behavioural signals to change consumption in different seasons and potentially disadvantage customers that typically consume only in one season. This effect would however also be in place for any 6-month option.

The ESO has considerable reservations about the accuracy of setting a charge 9 months out as there is the potential for lots to change after setting the tariff, before the charge comes into effect. Therefore, the preferable approach for the ESO would be a 12-month varying fix with 2 months' notice provided to industry. This would need to be slightly more than two months' in actuality to align with the required timescales for setting the domestic price cap which would be published on the 5th working day in February.

The Task Force discussed the options at length and recognised an inevitable trade-off between the total time of fix period plus notice period with the ESO preferring a shorter total time period and suppliers and customers preferring as long as possible. A reasonable compromise was felt to be a total time of fix period plus notice period of 14/15 months.

How to separate the months between fix lengths and the notice periods was not decided on by the Task Force and as such they recommend that further analysis is undertaken to determine which combination is best. Forecast accuracy is improved with a shorter notice period, reducing shortfalls or over-recoveries and reducing overall ESO financing costs. This comes at the detriment to suppliers' ability to factor the fixed charge into their pricing reducing the benefit of a fixed charge in reducing risk premia. More analysis needs to be undertaken to determine the best combination.

Task Force conclusion on Deliverable 2 and Next Steps

The Task Force recommends that Balancing Services Charges should be recovered through a charge which is fixed ex ante. The Task Force recommend by majority that the charge should be volumetric (£/MWh). The combination of fixed and notice period should be 14/15 months.

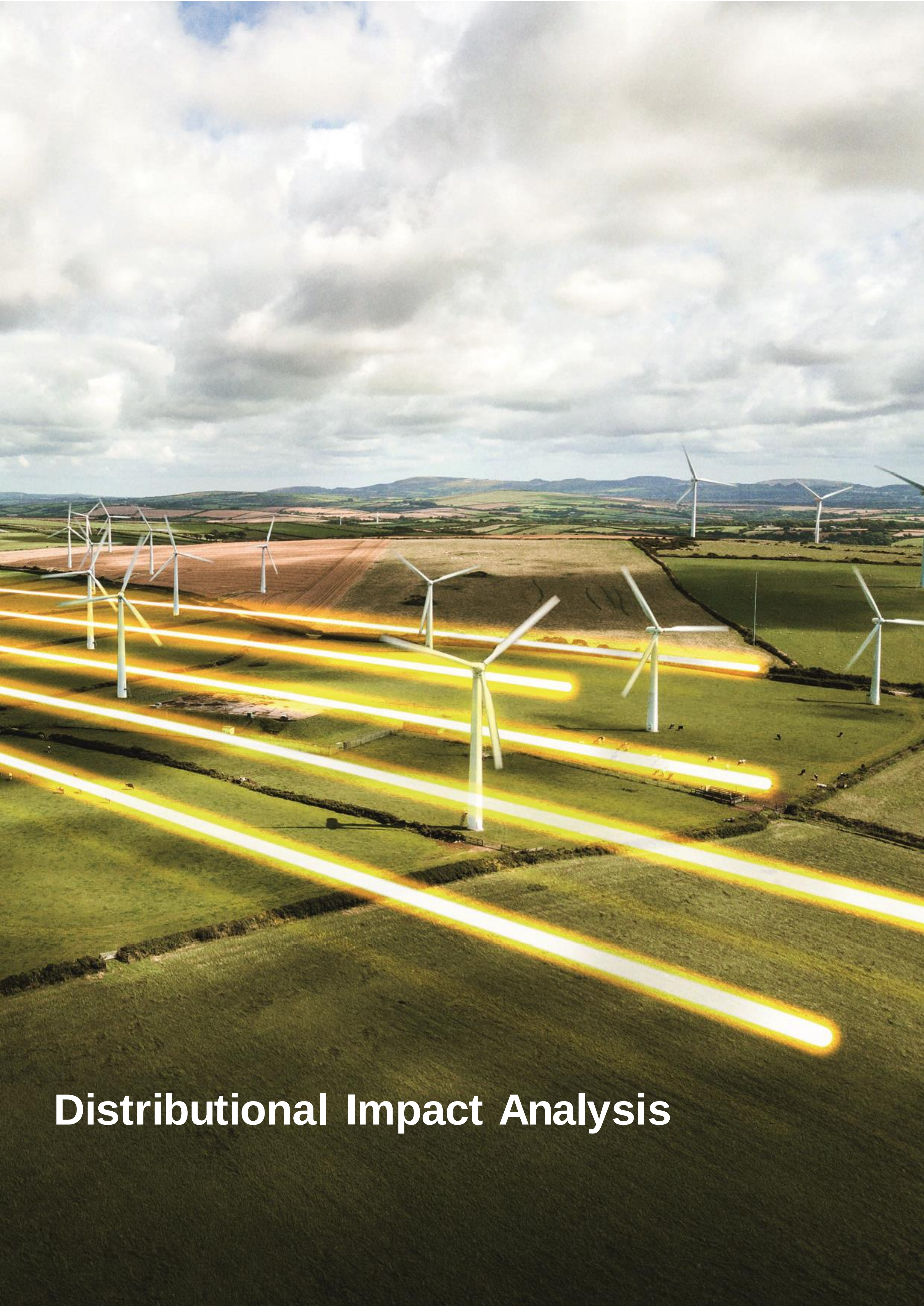
The Task Force have recommended by majority that the most appropriate methodology for BSUoS is a fixed volumetric charge. The key reasons for this decision were:

1) BSUoS is a charge relating to an energy service, this is different in principle and effect to asset recovery costs such as TNUoS or DUoS, it is therefore more appropriate to link the recovery of balancing services costs to volume rather than capacity or to a single site.
2) A volumetric charge minimises the distributional impacts of the change to the methodology as it is most similar to today. This would reduce the risk of over-burdening demand customers and assures that the charge will be easier to factor into suppliers' tariffs.
3) A volumetric charge is simple, there will be a single, fixed £/MWh charge for industry parties to manage rather than a set of per site charges which would be difficult to translate into customer tariffs. This feature ensures smooth implementation and a transparent tariff that is easier for customers to understand and relate to their own usage of the system.
4) The TDR/DDR charging bands are as yet, untested. There were concerns from the Task Force that a banded methodology creates "cliff edges" between one band and another producing a significant commercial incentive for sites to engage in charge avoidance behaviour. The Task Force did acknowledge that charge avoidance of a per site charge was more difficult but the commercial reward for successfully moving bands would act as a strong incentive.

The Task Force weighed up the pros and cons of both a volumetric (£/MWh) charge and a banded site-based charge (£/site). The pros and cons table specifically considered a banded charge with the same methodology as will be used for the TDR from April 2022. Whilst the Task Force were aware that Ofgem had developed this methodology for network residual charging which is another cost recovery charge like BSUoS there were concerns that the banded methodology would introduce some new distortions and inequitable outcomes. The Task Force were, on the other hand, aware that a volumetric fixed charge can be avoided more easily than a per site charge by installing behind the meter generation and making efforts to reduce consumption.

Initial conclusions on Deliverable 2 at the point of industry consultation were that a fixed BSUoS charge would deliver overall industry benefit. These conclusions still stand after a review of the consultation responses where all respondents who offered a view backed a fixed charge. The Task Force were mindful that this conclusion depends on the size of supplier risk premia compared to ESO costs of financing and remuneration for risk bearing services and this needed to be considered by Ofgem in their response. The Task Force recommended that including a cap on under-recovery would undermine the concept of a fixed BSUoS charge and reduce the consumer benefits identified. Additionally, the Task Force encourage Ofgem in their response to consider ESO financing requirements and potential license changes alongside the CUSC modifications to implement the methodology changes to ensure a holistic approach catches any inconsistencies.

The Task Force recognised an inevitable trade-off between the total time of fix period plus notice period with the ESO preferring a shorter total time period and suppliers and customers preferring as long as possible. A reasonable compromise was felt to be a total time of fix period plus notice period of 14/15 months. How to separate the months between fix lengths and the notice periods was not decided on by the Task Force and as such they recommend that further analysis is undertaken to determine which combination is best.



Distributional Impact Analysis

Domestic Consumer Impacts

Deliverable 1

The Task Force noted the TCR principles and their conclusions regarding the treatment of "cost recovery" costs. Consideration was also paid to a previous modification, CMP201[22] raised in 2014, which sought to move Balancing Services Charges wholly onto final demand and which was not approved by Ofgem. At that point, Ofgem concluded that 'we are concerned that at this time the potential benefits this would bring would not be material enough to offset the potential costs to consumers from implementing the modification'. This concern resulted from Ofgem's view that in the short-term, increasing GB generation relative to European counterparts through removing Balancing Services obligations would increase demand for GB generation and therefore, bring more expensive, marginal plant into merit. As a result, wholesale prices in GB would increase in the short-term, offsetting around 50% of the direct reduction in wholesale price brought about by the removal of BSUoS. In the longer-term, this should create consumer benefits as higher short-term revenue would lead to increased investment in GB generation and bring down the wholesale price once more.

In 2014, Ofgem considered this long-term benefit sufficiently uncertain that it rejected the modification.

CMP308, which proposes the same solution as its predecessor CMP201, brought forward a theory that the market had evolved somewhat from 2014 to reduce these short-term consumer impacts. The most recent analysis for CMP308 showed a positive short-term impact for consumers as long as the differential was less than 15p/MWh between the base case marginal plant and the prices submitted by the marginal plant post BSUoS reform. It is not possible given the short time scales for the Balancing Services Charges taskforce to undertake modelling and a broader impact assessment. Acknowledging this uncertainty around the short-term consumer impacts, the Task Force recommend that a quantitative assessment of this should inform Ofgem's final decision on these reforms.

Deliverable 2

When considering the structure of Balancing Services Charges for the second deliverable, the Task Force considered analysis undertaken through the TCR which focussed on the distributional impacts of moving to a fixed charge. In the TCR, this was particularly pertinent for energy intensives and domestic consumers potentially in fuel poverty. For the latter, this focused on whether or not those in fuel poverty would be disproportionately impacted by the shift from a volumetric to a fixed charge.

A report by 'Grid Edge Policy' and supported by consumer group Citizen's Advice[23] raised concerns that the movement to a fixed charge for the TDR and DDR would disadvantage those in fuel poverty who on average "use less energy and hence will pay more while those on high incomes will on average pay less, in some cases significantly less". BSUoS costs are currently smaller than the network Residual charges (Distribution Residual and Transmission Residuals combined) considered within the TCR. However, it is still expected that some of these distributional impacts will continue to be relevant. The distributional impact, including these considerations, should be assessed as part of any impact assessment ahead of Ofgem's final decision on these reforms.

Distributional Impacts

The following analysis uses the example tariffs displayed on page 25.

The Task Force explored the distributional impacts of their recommendations on domestic consumers. The thirteen consumer archetypes used by Ofgem in their TCR analysis were used to show an example of how the Task Force's recommendations could impact domestic households. Household volumes used in the TCR analysis were uplifted by 9.2%[24] to account for losses that under the current methodology suppliers and

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[22] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp201-removal

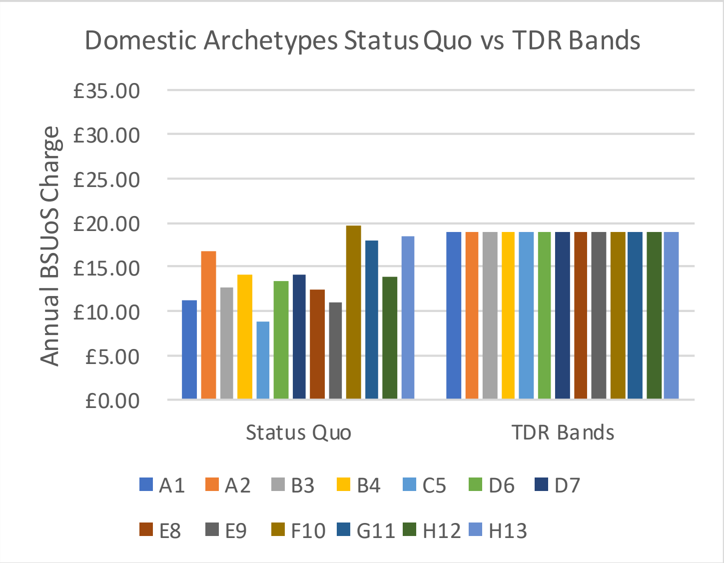
[23] https://b13f0e05-ddc3-484d-ab4f-7e31f496e1c8.filesusr.com/ugd/140d4b_d97aba68981041978c5367c405c1eca1.pdf

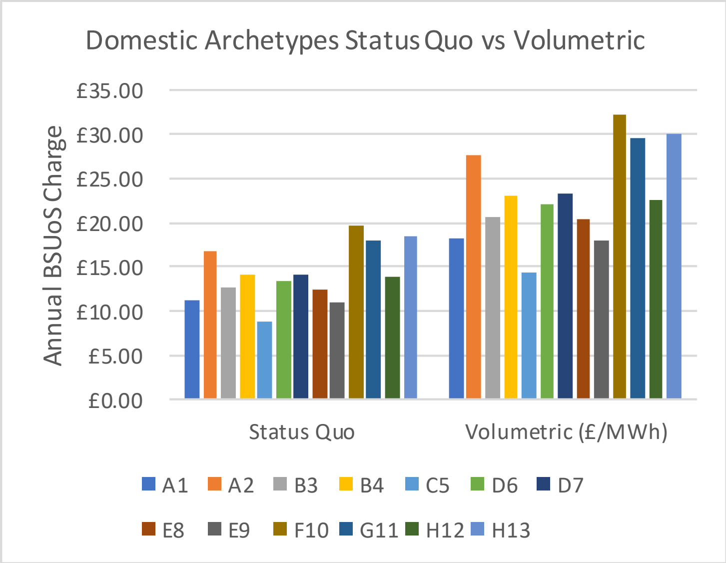
[24] https://www.ofgem.gov.uk/system/files/docs/2020/08/annex_3_-_network_cost_allowance_methodology_elec_v1.6.xlsx

generators share a portion of in their chargeable volumes for BSUoS. Under the proposed new methodologies, the chargeable volumes or sites will be measured at the meter point for each user and so losses are not included in the calculation but consumption from interconnector imports and distributed generation would be which are ignored from the methodology today.

An important point to note is that the volume used for example tariff setting for the “new methodology” banded and volumetric tariffs was separated into components for domestic, non-domestics by voltage tier and unmetered supplies. The volume data used for domestics is on average 0.6MWh lower than that used for Ofgem’s consumer archetypes. This means that for the banded option, in particular, the impact of the Task Force’s recommendations is understated.

The graphs below show a comparison between the annual BSUoS charge under the status quo methodology today and the potential new methodology of either a fixed volumetric or TDR banded charge where Final Demand only pays BSUoS.





Industrial & Commercial Consumer Impacts

The Task Force noted that the increase in direct costs to customers, notably the large and intensive users operating in international markets, may create incentives which may have unintended consequences. For this type of customer there are a number of increasing energy costs that may influence their energy usage, such as the Final Consumption Levies (FCLs), changes to the distribution and transmission charging regimes, and carbon taxes. In order to avoid some, or all of these costs, the customers may be able to reduce their energy usage and/or their reliance on public electricity supplies, allowing them to reduce the size of their connection and charges related to electricity imports. In the most extreme cases customers may be able to move their businesses offshore or may have to shut as they become uncompetitive.

The Task Force considered whether the charging of Balancing Services Charges on a volumetric (£/MWh) basis or as a fixed capacity charge (£/site) would incentivise customers to change their behaviour to avoid the charge. Evidence shows that the existing volumetric BSUoS charge is currently avoided by some customers who reduce or move their energy usage between times of high and low BSUoS charges. Customers also are observed acting to avoid volume-based Network Charges. The ESO estimates some 600MW of demand reduction occurs over the Triads. The Task Force, therefore, felt that load shifting in response to the charge was a risk, as while electricity demand is inelastic for most types of customers, for those where electricity is a high proportion of their total cost it is more elastic. Some of the Task Force therefore felt this potential change in consumption should be considered as the Task Force had already agreed that balancing services costs should be treated as “cost recovery”. Allowing customers to “avoid” cost recovery charges is not in line with Ofgem’s wider TCR conclusions and therefore the incentives and the ability to avoid the charge should be minimised.

The use of a fixed capacity-based charge also has its challenges, especially when constructed as in Ofgem's TCR work, most notably in how to set charging bands. A fixed period charging methodology also carries the potential risk of greater over/under-recovery between years. The existence of the "k factor" in price controls is a means to manage this risk but can create significant variation in charges between years. There were concerns that industrial and commercial customers, faced with not just a high, unavoidable balancing services charge but also other, increasingly onerous charges, may go "off-grid" or shut down completely, taking production offshore. The Task Force made no research into where a tipping point to that decision may be and recognised it would differ for different customers. However, the Task Force noted that the Government's Energy Intensive Industries (EII) scheme and Climate Change Agreements[25] were a clear recognition that the UK Government were concerned that internationally competitive industries faced an undue competitive disadvantage from the UK's various FCLs and carbon policies.

The Task Force did not think it would be appropriate to give larger energy users any form of discount on the same type of basis that the EII scheme works, as size of demand may not be an indication of energy intensity. It was also noted that the TCR seemed to also charge larger customers proportionally more than smaller customers. Though banding for BSUoS could be different from that used for DUoS/TNUoS, it would be administratively simpler to use the same bands. Many of these companies will be international businesses and therefore there is a real risk that they could shut UK operations and move them to other countries. The Task Force did not believe that it would be Balancing Services costs on its own that would trigger such behaviour, but the cumulative effect of the various charges would impact some customers' ability to remain competitive in their own markets. The Task Force believed it was vital for Ofgem to fully assess the cumulative impact of all of its proposed policy changes.

The Task Force observed that going off-grid is difficult, but it may be possible for parties who can use grid back up to run safety systems only and rely on on-site generation for the vast majority of their energy needs. Where customers "self-supply", relying on their own generation rather than imports, they avoid many costs, like the FCLs, and reduced connection sizes would also lower network related costs, but the number and size of customers who may be able to take this course of action was unknown. It was further noted that the customers who could install on-site generation may also be able to put such plant in the capacity market (CM) as a means to fund such new build, though under the CM Rules they would need to maintain a connection for export.

The movement of operations offshore or installation of on-site generation was likely to have a negative effect on greenhouse gas emissions. The EII scheme was in part set up to stop "carbon leakage", a common concern when industries move production to countries with lower environmental standards, less renewable energy within the generation mix, etc., to keep their costs down. The Task Force also thought on-site generation was far more likely to be gas fired generation to enable consistent, electricity supplies. Again, these effects could not be quantified, but the Task Force believed that Ofgem should consider them in reaching a decision.

Distributional Impacts

The following analysis uses the example tariffs displayed on page 25.

The range of power consumption and capacity needs of non-domestic consumers is substantially larger than for domestic households and as such the banded charging methodology attempts to group similar customers together and ensure that they pay the same unavoidable residual charge whilst separating very different customers to ensure that smaller sites are protected. To perform some distributional analysis on the impact of the Task Force's recommendations, non-domestic sites were separated into voltage tiers. Consumption and capacity data from the July 2020 charging futures tariffs was used to create a spread of thirteen example sites in each voltage and banding type. Thirteen sites were chosen to represent a range of those sites in each voltage tier and to align in number with the domestic consumer archetypes used for distributional analysis for

[25] Widening eligibility for renewable electricity cost relief schemes – June 2018
https://www.gov.uk/government/consultations/widening-eligibility-for-renewable-electricity-cost-relief-schemes#history
Climate Change Agreements scheme extension and reforms for any future scheme – April 2020
https://www.gov.uk/government/consultations/climate-change-agreements-scheme-extension-and-reforms-for-any-future-scheme

domestic sites. To approximate the status quo annual BSUoS charge, volumes were uplifted for losses by 9.2%[26] for those sites connected to the distribution network and for the transmission connected sites a 1% uplift was made to reflect that this volume would likely have fewer losses attributed.

It is important to note that the settlement period price fluctuations of the status quo methodology have not been incorporated into these examples. This is because too many assumptions would be required on the time of consumption and load for these example customers and sufficient data granularity was not available. There will be distributional impacts related to the move from an ex post calculated charge to an ex ante fixed charge whether banded or volumetric. From a principle-based perspective the Task Force believed that greater certainty over the BSUoS charge would deliver overall consumer benefit, but this hypothesis has not been tested for distributional effects.

Low Voltage (LV) Connected Non-Domestic Final Demand Sites

Altogether there are just over 2 million non-domestic premises connected at LV in the data set used for this analysis with 91% of them having no agreed capacity with their respective DNO. The 91% without an agreed capacity are banded using their estimated annual consumption in the “LV No MIC” group whilst those with an agreed capacity are banded based on their capacity in the “LV MIC” group.

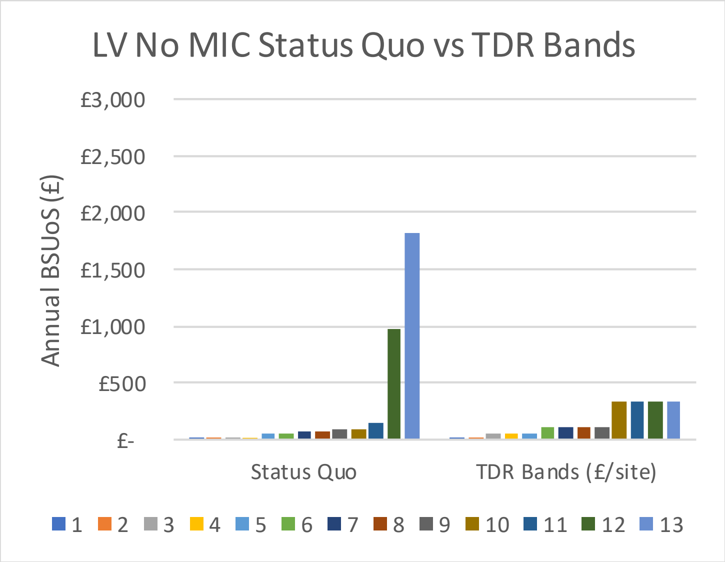
LV No MIC – Distributional Impact Analysis

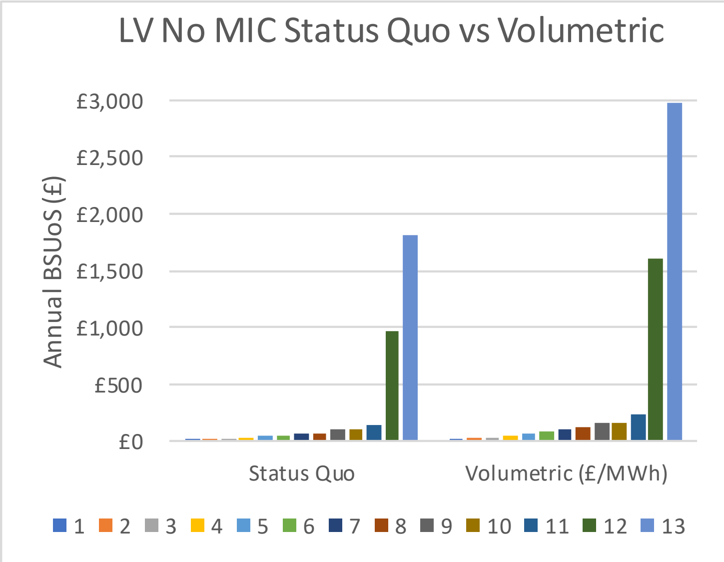
The thirteen anonymised LV No MIC sites are shown in the table below. As these sites are banded based on annual consumption data rather than capacity there are no common values and so a selection from across the range have been included in the sample. Focus has been on the different outcomes for sites at either side of a boundary as those sites would experience potentially more extreme distributional impacts from a banded approach as oppose to a volumetric approach. It is worth bearing in mind that sites on either side of a boundary are at the extremes of their group and, whilst actual customer examples, are not necessarily representative of the experience of their cohort as a whole.

Site	Capacity (kVa)	Annual Metered Volume (kWh)
1	n/a	1,196
2	n/a	3,804
3	n/a	4,738
4	n/a	7,115
5	n/a	13,012
6	n/a	14,392
7	n/a	18,472
8	n/a	21,268
9	n/a	27,549
10	n/a	29,125
11	n/a	40,698
12	n/a	284,784
13	n/a	531,513

Distributional impacts for these thirteen sites are shown in the graphs below.

[26] https://www.ofgem.gov.uk/system/files/docs/2020/08/annex_3_-_network_cost_allowance_methodology_elec_v1.6.xlsx





The stand out feature of this analysis is Site 13, the largest site in the sample. The annual BSUoS charge under the status quo approach is closely tied to the MWh volume consumed and as a large consumer Site 13's expected charge is also large. This leads to a significant reduction in charge on a move to a banded BSUoS approach as Site 13 would face the same charge as all others in its cohort.

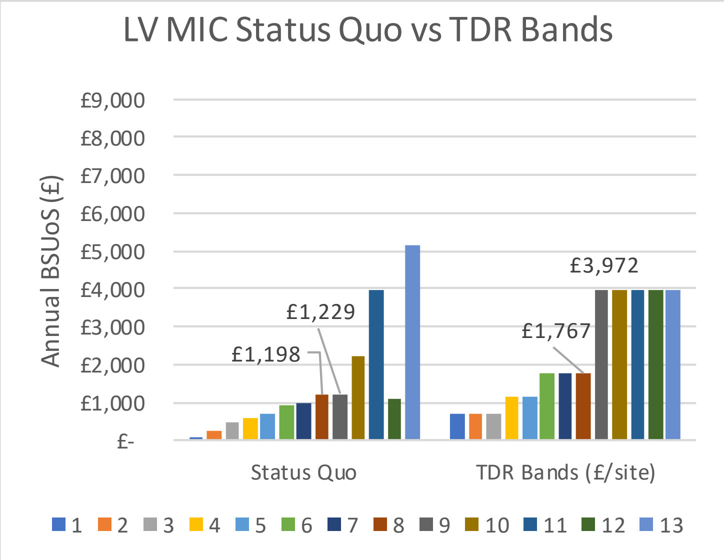
LV MIC – Distributional Impact Analysis

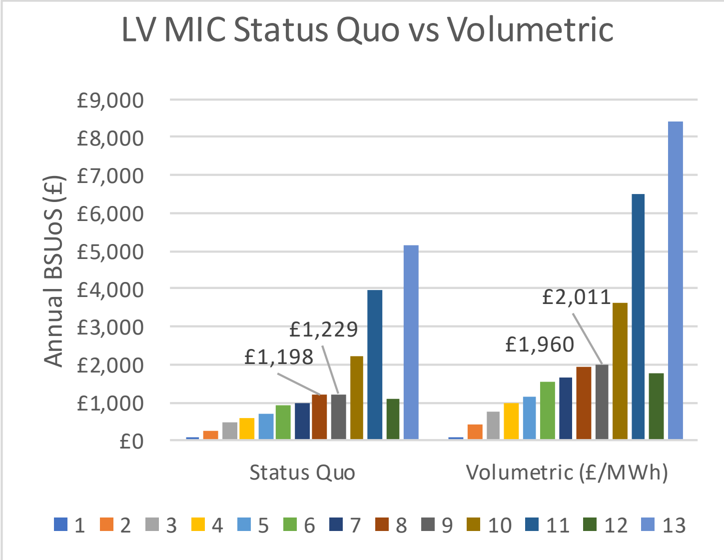
The thirteen anonymised LV MIC sites are shown in the table below. Where possible this analysis avoids the extreme outliers of a group and aims for fairly average members of a cohort. For example, there are 1405 sites with an agreed capacity of 350kVa, a site close to the average annual consumption of this cohort has been chosen. Equally, where possible capacities which are common to many sites have been chosen avoiding non-round capacities to avoid accidently choosing an unusual subset of non-domestic sites.

Nonetheless, special attention has been paid to the different outcomes for sites at either side of a boundary as those sites would experience potentially more extreme distributional impacts from a banded approach as oppose to a volumetric approach. It is worth bearing in mind that sites on either side of a boundary are at the extremes of their group and, whilst actual customer examples, are not necessarily representative of the experience of their cohort as a whole.

Site	Capacity (kVa)	Annual Metered Volume (kWh)
1	10	17,989
2	50	77,087
3	70	135,081
4	100	173,787
5	140	205,125
6	160	274,432
7	200	293,400
8	225	349,444
9	240	358,460
10	350	643,465
11	400	1,158,508
12	550	310,525
13	1,000	1,504,987

Distributional impacts for these thirteen sites are shown in the graphs below.





Two notable sites have been pulled out with data labels showing their charge before and after implementation of the Task Force's recommendations. These are sites 8 and 9 in the example and use real customer data. The distributional impact of site 8 of the Task Force's recommendations for BSUoS is an increase in the BSUoS component of their overall charge of +47% (assuming perfect pass through from suppliers, which is highly unlikely). For site 9 the increase under a TDR methodology is +223% compared to status quo BSUoS. Under the volumetric methodology this difference is +64% for both sites compared to status quo BSUoS. This discrepancy in distributional impact is as a result of the step change in banding as Site 8 is a large site for their cohort whilst Site 9 is in a higher band and is a smaller member of its cohort.

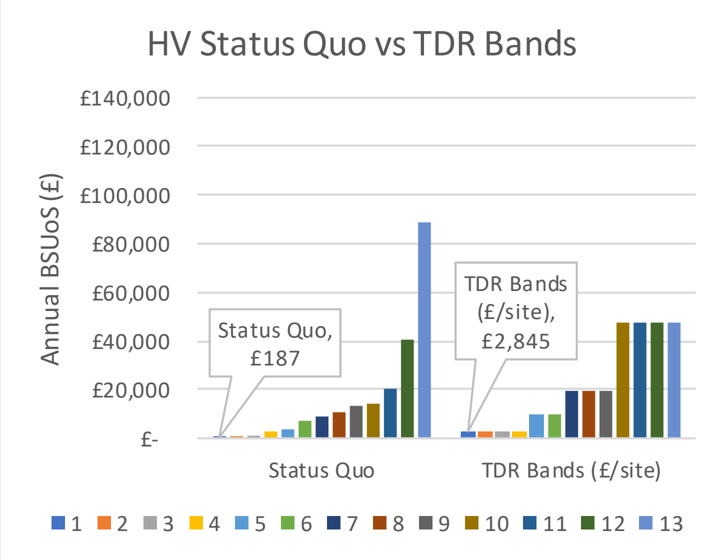
A further point to note from this sample of thirteen sites is the impact on the smallest member of the group. Site 1 under the TDR banding methodology would face charges 10 times higher than under Status Quo BSUoS. Under the volumetric option the increase is (as with all other members of the sample) +64%.

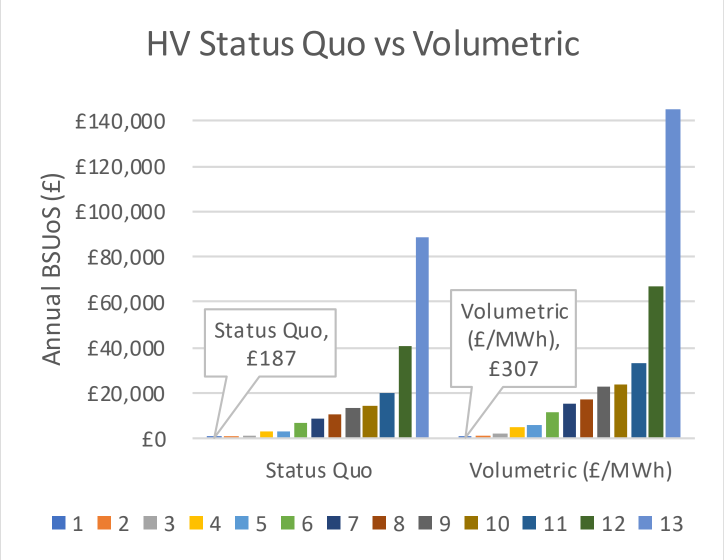
High Voltage (HV) Connected Non-Domestic Final Demand Sites – Distributional Impact Analysis

There are almost 23,000 Final Demand Sites connected at HV on the distribution network. All HV connected sites will have an agreed import capacity with their DNO.

Site	Capacity (kVa)	Annual Metered Volume (kWh)
1	50	54,679
2	100	213,244
3	200	342,681
4	400	938,358
5	500	1,000,474
6	950	2,085,958
7	1,100	2,659,728
8	1,500	3,065,953
9	1,700	4,008,498
10	2,000	4,188,018
11	2,500	5,902,816
12	5,000	11,850,604
13	10,000	25,879,338

Distributional impacts for these thirteen sites are shown in the graphs below.





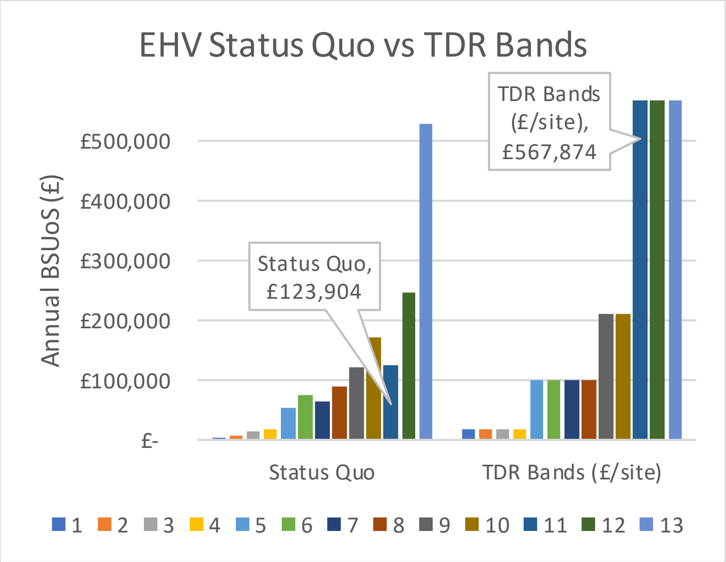
Again, with this voltage group the step changes in BSUoS charges between the bands can be seen clearly. A key distributional impact to note is shown in the data callouts. The impact on a small site, Site 1 in our sample in this instance, is considerable in a banded methodology. The estimated annual BSUoS charge would increase by over 14 times the status quo charge. This would be likely to have a significant impact on the affected businesses' overall yearly electricity expenditure. In the dataset used for this analysis there are over 1,700 HV demand connections of either 50kVa or lower agreed capacity. This suggests that there would be major distributional impacts on this group in particular were BSUoS moved to a banded charge.

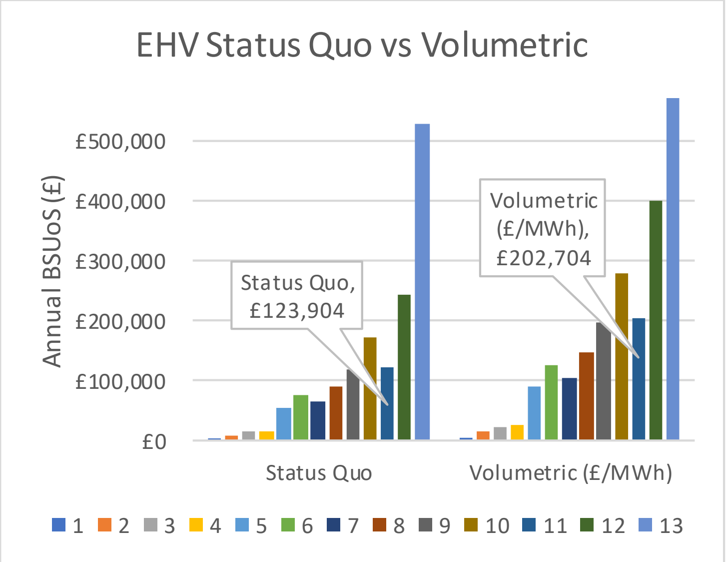
Extra High Voltage (EHV) Connected Non-Domestic Final Demand Sites – Distributional Impact Analysis

There are 888 Final Demand Sites connected at EHV on the distribution network. All EHV connected sites will have an agreed import capacity with their DNO.

Site	Capacity (kVa)	Annual Metered Volume (kWh)
1	500	1,013,225
2	1,000	2,432,058
3	2,000	4,028,284
4	3,500	4,867,366
5	5,000	15,856,659
6	8,000	22,229,866
7	10,000	18,533,562
8	11,000	26,439,319
9	15,000	35,006,491
10	18,000	50,046,391
11	25,000	36,135,426
12	30,000	71,498,648
13	60,000	154,278,441

Distributional impacts for these thirteen sites are shown in the graphs below.





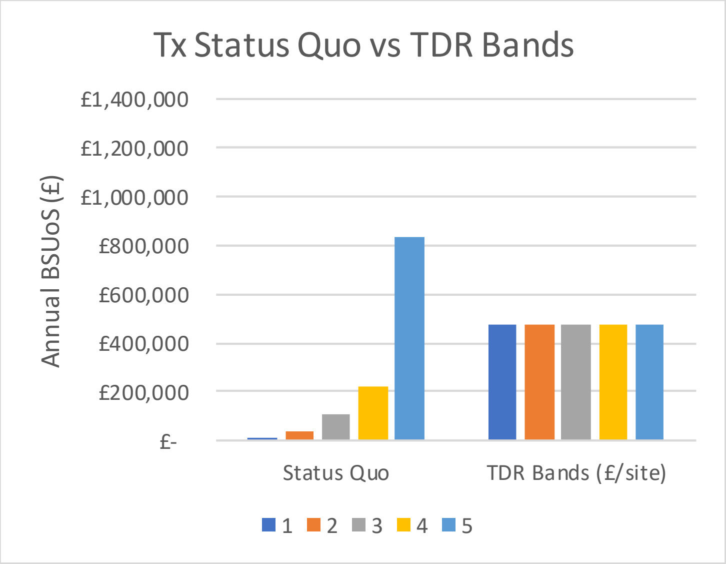
The data callout for this voltage level is on Site 11 in the sample. Site 11 is a relatively small consumer for its 25,000kVa agreed import capacity. Although it is the 6th smallest consumer of the 12 sites in the data subset with 25,000kVa import capacity (so not unusual by any means). A banded charge shows a +358% increase in expected annual BSUoS whereas a volumetric charge is only the across the board standard +64%. This site was chosen for the sample as it is not actually an outlier (sitting at the median of its small cohort) but looks like one in analysis of the distributional impacts. This is further compounded in a cross-sample comparison by comparing Site 11 with Site 10 which is in Band 3 and faces a lower banded charge but is actually a much larger consumer. Again, Site 10 was chosen as an average member of the cohort with import capacity 18,000kVa so is not a particular outlier.

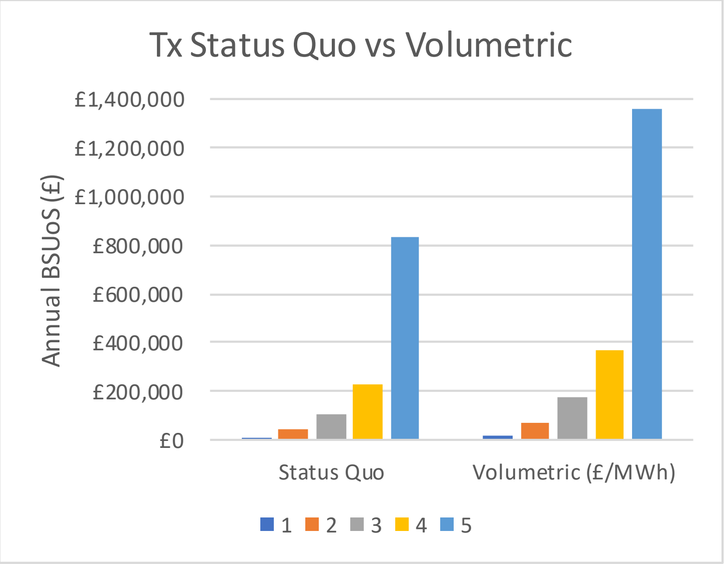
Transmission Connected Non-Domestic Final Demand Sites – Distributional Impact Analysis

There are just 62 identified Final Demand Sites connected to the transmission network that under the Task Force's recommendations will be liable for BSUoS charges. The CUSC modification, CMP343 which introduces charging bands to the TNUoS charging methodology has yet to be approved for implementation by the Authority and as such a decision on whether there will be one, two or four transmission charging bands is yet to be made. Banding, were it to take place, for transmission connected demand sites would be based on annual consumption as there is currently no agreed import capacity for transmission connected demand. As such it is impossible to select a sample of average sites as all sites in this cohort are materially different. Consequently, to create a sample the Task Force selected 5 sites from across the range of the 62 sites and compared to a one band option although were mindful that a two or four band option could be decided on by Ofgem when CMP343 is received by the Authority for a decision.

Site	Capacity (kVa)	Annual Metered Volume (MWh)	Rank /62*
1	n/a	2,636	2
2	n/a	12,085	9
3	n/a	31,177	25
4	n/a	65,405	40
5	n/a	242,896	57

*Ranking is from smallest (#1) to largest (#62) based on 2019/20 annual consumption

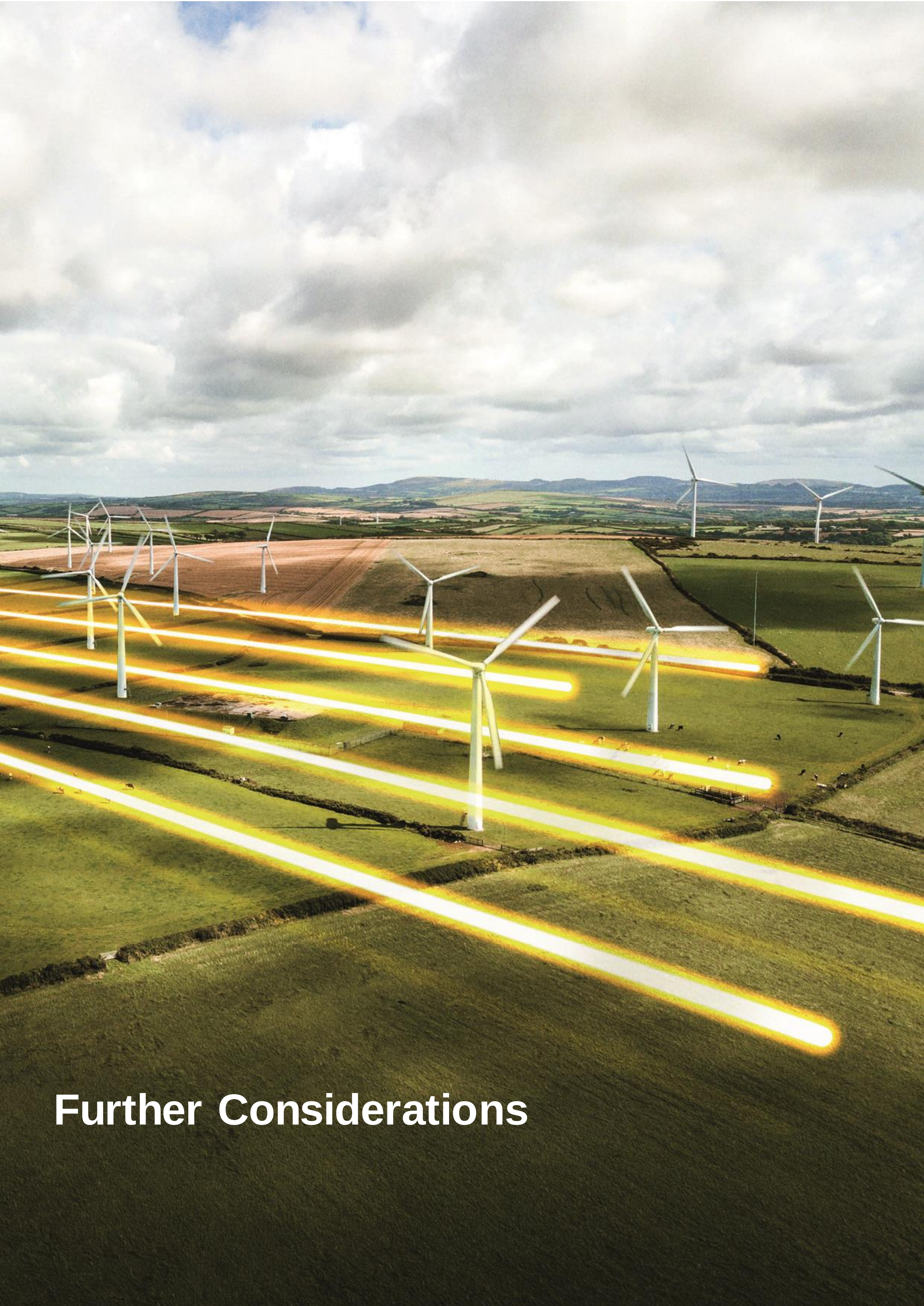




There are distributional impacts for transmission connected Final Demand sites too. At transmission the small cohort of sites are distributed with a long tail at the large consumption end of the distribution. This means that these sites under a banding methodology are inevitably pulling in far more of the total charge pot than a median average site. This approach creates a redistribution of the charge from large consumers to smaller ones in the same cohort at a greater magnitude than for the cohorts where sites are normally distributed.

Task Force's Conclusions on Distributional Impact Analysis

The Task Force considered the analysis and the conclusions drawn added support to their recommendation for a volumetric BSUoS charge. A volumetric charge has far less distributional impact than a banded charge.



Further Considerations

Implementation of the Task Force's Conclusions

Notice to industry prior to implementation was a key focus for the Task Force and a recommendation focussing on essential implementation considerations has been included in this report. The Task Force agreed that two years' notice from the point of publication of Ofgem's response to the Task Force report, would be sensible prior to implementation. This was due to the fact that many supplier contracts for purchase of power from the wholesale market were up to two years in duration and fixed price contracts with customers were typically no longer than two years. The recommended implementation timeframe would therefore allow the market to avoid the majority of windfall gains and losses as the majority of fixed contracts would expire in the two years between publication of Ofgem's response and implementation.

The Task Force recommendation for Deliverable 2 is for the ESO to fix Balancing Services charges ex ante and to have a given notice period of this fixed charge to industry. The interaction between the suggested two-year notice of implementation and the notice period of the first fixed charge should not unduly delay implementation. The Task Force propose that the notice period of the first fixed charge is included within the two-year notice of implementation such that the implementation date is the same as the date from which the first fixed BSUoS charge is applied.

The COVID-19 pandemic lockdowns have led to significant demand reductions across GB. Periods of very low demand that have coincided with high wind and/ or solar generation led to marked increases in BSUoS charges from April to June.

SSE raised CUSC modification CMP345 in response to this situation, which proposed to defer a portion of the increased BSUoS charges from May – August 2020 to the 2021/22 charging year. Ofgem approved WACM2 of the modification, which caps BSUoS charges for a period at £15/MWh from 25 June to 31 August. Charges in excess of the cap will be recovered from all users in 2021/22. Following this, British Gas raised a further CUSC modification CMP350 which was approved by Ofgem for implementation on 14th August 2020. Ofgem decided to approve and direct implementation of WACM6 of CMP350: this WACM reduced the cap on BSUoS charges from £15/MWh to £10/MWh from implementation on 14th August extending this out from the original CMP345 date until 25th October 2020. A limit on the amount deferred under this scheme was set at £100million.

The workgroup process and consultation for CMP345 and CMP350 highlighted the difficulty facing industry in managing the risk of unexpected events that significantly suppress demand and increase BSUoS charges. In the short term, until 25 October 2020, the cap will shift some of this risk from market participants to the ESO. The Task Force recommendations set out how this risk should be managed in the longer term through an ex ante fixed charge. Until a new charging structure is in place, market participants will continue to face the risk of periods of unexpected, very high BSUoS charges.

Alongside this risk for all market parties from the current BSUoS methodology, delaying implementation would continue the existing harmful distortions between generators who pay BSUoS and those who do not. The Task Force acknowledged that it is important to find a balance between providing sufficient notice to help avoid windfall gains and losses with the need to unlock the potential benefits from regime change.

Given the 2-year notice prior to implementation recommendation and the awareness of continuing market distortions the Task Force discussed the feasibility of an interim solution. Feasibility very much depends on the nature of the interim solution and the extent of system and process changes required but broadly the Task Force felt that a partial change would add to the implementation cost of the enduring solution and create confusion and uncertainty for industry without necessarily correcting the market distortions. Additionally, there were concerns that a change which materially altered the generation demand split of the total BSUoS pot would undermine the requirement for 2 years notice agreed by the Task Force. The Task Force decided to include a specific consultation question on interim solutions for respondents to bring forward their views on interim solutions for a further discussion before the Final Report was submitted to Ofgem.

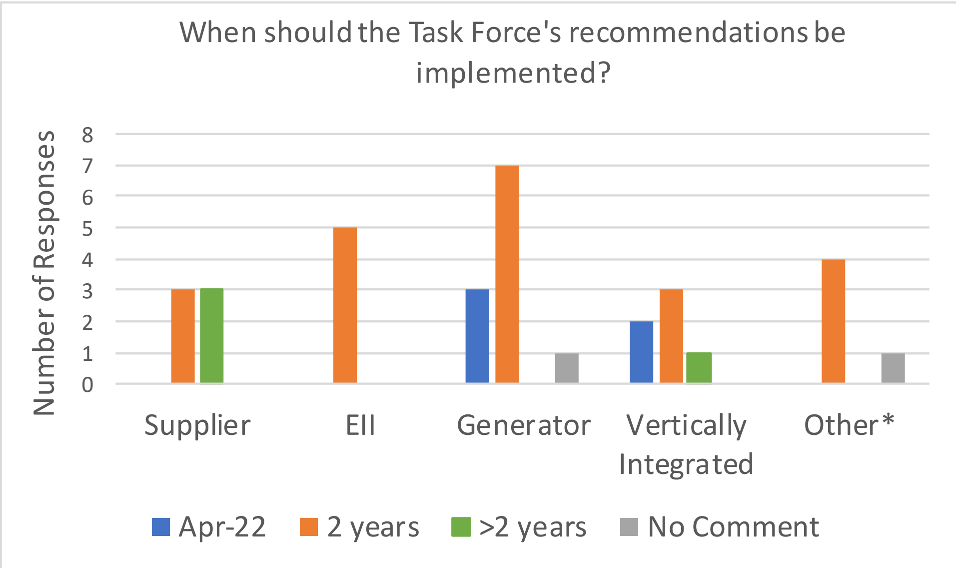
Following receipt of the consultation feedback and further discussions the Task Force recommend that an interim solution should not be pursued. Focus for all industry parties should be on delivering the enduring solution.

Consultation Feedback

Question 7 on the consultation asked respondents whether they supported a two-year notice period prior to implementation of the Task Force's recommendations.

7. Is 2 years' notice of the changes prior to an implementation date appropriate? Please state your reasoning and evidence behind your answer.

In general, amongst the responses, there was an acceptance that balance had to be struck between acting to remove harmful distortions in competition between GB transmission connected generators and other generators and providing notice to industry to allow forward price agreements to unwind protecting suppliers and consumers from undue losses. The majority of responses agreed with the Task Force that two years notice strikes that balance well.



Responses from generators were keen to emphasise that the longer the implementation period is the longer harmful distortions exist whilst suppliers and vertically integrated organisations drew out potential exposure to longer term agreements. Overwhelmingly every response called for clarity as soon as possible over the implementation date. The Task Force agreed that to enable successful implementation and to avoid windfall gains and losses as far as is practicable, the implementation timescales needed to be clearly conveyed in Ofgem's response to the Task Force's report. This will provide clarity for industry parties to make decisions regarding their tariff pricing, wholesale pricing and CM or CfD bidding strategies.

Question 8 on the consultation asked respondents for their opinions on any interim solutions the Task Force should consider.

8. Should the Task Force consider any interim measures? Please provide details of any suggested interim solution including how it may deliver benefits to consumers or help to mitigate specific challenges facing market participants, whilst limiting any windfall gains or losses between industry participants.

The overwhelming majority of respondents were not in favour of interim measures citing greater complexity and time burden on industry in their reasoning. As such the Task Force will continue with their initial recommendation that an interim solution is not appropriate; focus should be on delivering the enduring solution.

Implementation and RCRC

For all Settlement Periods, the Total Residual Cashflow (TRC) is calculated as being the sum of all energy imbalance charges across all parties and accounts. This value represents the total amount of money to be redistributed (or collected) via the Residual Cashflow Reallocation Cashflow (RCRC). RCRC and BSUoS are closely interlinked as periods with high imbalance tend to have high Balancing Services expenditure which leads to both a high BSUoS price and large RCRC debits or credits. The RCRC methodology should be considered as part of the resulting industry code modification processes due to its close relationship to BSUoS. If BSUoS is recovered from a different cohort of industry there may be unintended consequences if RCRC is not also reviewed. In particular, energy imbalance action costs recovered through BSUoS and charged onto Final Demand could trigger a credit to all parties capable of imbalance through RCRC; only a subset of whom would be liable for BSUoS.

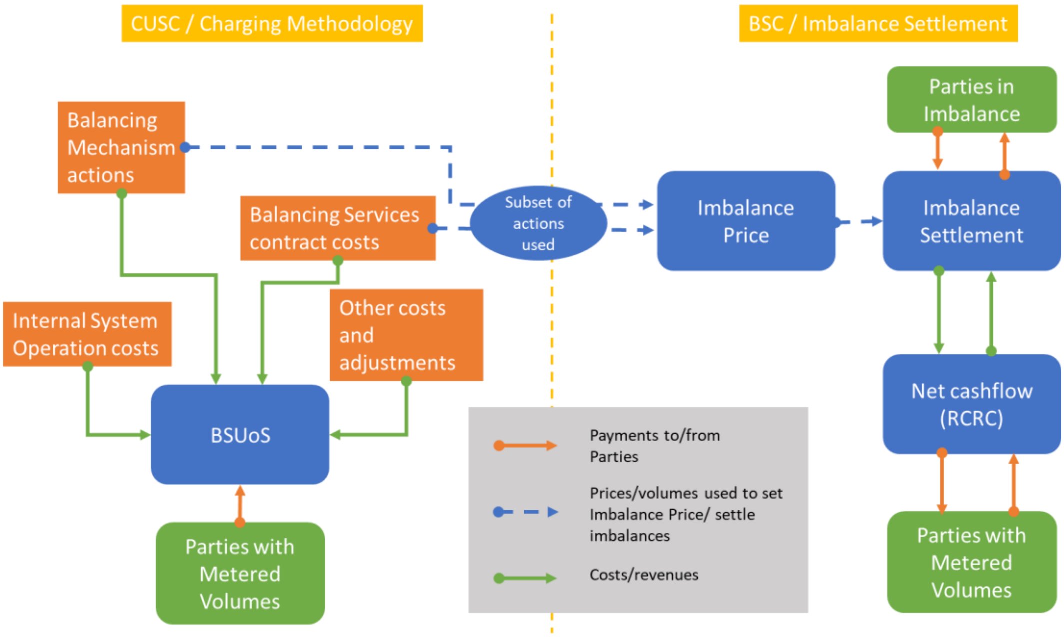
The Task Force invited ELEXON along to a Task Force meeting to discuss the potential for double counting in the charging of RCRC and proposed changes to the BSUoS methodology. The Task Force noted that when BSUoS charges were removed from interconnectors through CUSC modification CMP202 a corresponding change was made to RCRC to remove interconnectors from this credit/debit payment.

To further explore the interactions between RCRC and BSUoS the Task Force created the below diagram.

The diagram below shows a simplified representation of the interaction between BSUoS and RCRC. The left side of the diagram shows the BSUoS charging and payment process under the CUSC. The right side illustrates the imbalance settlement process under the BSC.

A number of costs are incurred by the System Operator (SO) when balancing the system, including actions taken in the Balancing Mechanism and other Balancing Services. All of these costs are recovered through BSUoS and parties pay in proportion to their metered volumes. The volumes used for this come from the BSC settlement processes.

A subset of these balancing actions are used in the BSC process for setting imbalance prices to be used in imbalance settlement. Imbalance settlement is necessary so that there are the correct incentives in place to ensure that parties manage their imbalance positions by trading appropriately prior to the contract submission deadline. However, it also results in a net cost recovery or deficit. This makes sense. For instance, in a short market, there would be expected to be more short imbalances paying imbalance price than long ones being paid the imbalance price, resulting in a net revenue



The resulting surplus or deficit has to go somewhere. It cannot pass to Elexon as it is a non-profit organisation and any costs would ultimately be recovered from the market anyway. Industry parties currently pay the full costs of balancing through BSUoS and the imbalance settlement residual cashflow is kept totally separate and away from the SO. Instead, the cashflow (RCRC) is allocated to parties based on metered volumes. These are not identical volumes to those used in the charging of BSUoS, but are adjusted for any bid and offer volumes taken and any volumes reallocated to other parties. However, the principle is very similar to that of BSUoS with both Suppliers and Generators being exposed to RCRC.

If in future only suppliers are exposed to BSUoS, then it seems reasonable to reassess the allocation of RCRC, perhaps to change it to a similar basis. Given the relatively low levels of money presently reallocated through RCRC, this would not appear to be an urgent issue to address and could be progressed once there is more clarity on how BSUoS will be recovered going forwards.

Consultation Feedback

ELEXON and NGESO recommended through their consultation response that a BSC issues group would be the most appropriate forum to further consider changes to RCRC. Some respondents noted that they believed that RCRC was out of scope for the Task Force's recommendations, the Task Force agreed that there wouldn't be a solution recommended in the report but that an issues group was a sensible place to continue discussions. The Task Force agreed to draft a BSC issues group proposal form for submission to the BSC panel for consideration and next steps.

Implementation and ESO Pathfinder Projects

The ESO pathfinder projects are an innovative process designed to find the most economic and efficient solution to some of the system's security needs that have traditionally been met through the TOs. They introduce tenders in which traditional TO built solutions compete against market-based solutions to introduce competition and maximize savings for UK consumers. Cost reductions of £125.5m per year from 22/23 are expected to be achieved through the introduction of competition to network asset built. Market based solutions regularly include assets traditionally provided by TOs, such as sync compensators or reactors. These import a small amount of active power to provide the service (such as reactive power or voltage) they have successfully tendered for.

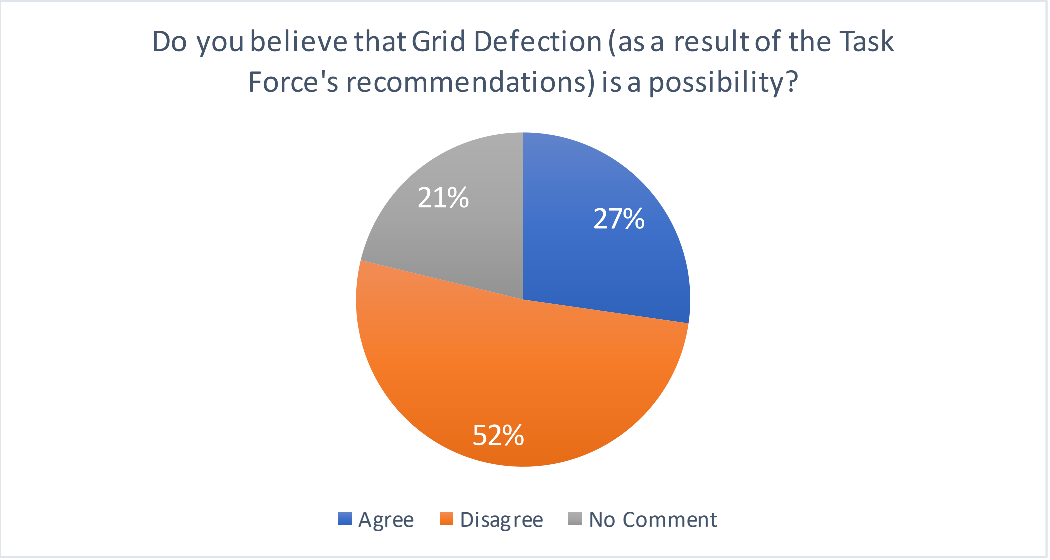
Through the development of the CUSC modifications for the Transmission Demand Residual (TDR) two definitions of Final Demand have been proposed, one which would specifically exclude voltage pathfinder projects from being categorised as Final Demand (sites that exclusively provide reactive power services) and the other that would consider all these sites to be Final Demand and therefore liable for Final Demand network charges. Further work and discussions with Ofgem are planned, as if only some pathfinder participants are required to pay the TDR, this creates a discrepancy to fair competition which may result in suboptimal consumer outcomes and savings of the Pathfinder tender exercise.

The Task Force considered how these sites should be charged in light of their recommendation for Deliverable 1 that Final Demand only should pay BSUoS. The Task Force believed that a "level playing field" was important for the consumer benefit of these tenders. The Task Force's recommendation is that sites which provide market-based solutions for transmission system services shouldn't be eligible for BSUoS charges if BSUoS charges are levied on Final Demand only. The Task Force were of the view that an enduring charging solution should be found for these sites and any balancing services charges they should attract.

Consultation Feedback

Question 2 on the consultation asked respondents whether they believed that "grid defection" as a result of the Task Force's recommendations was a possibility.

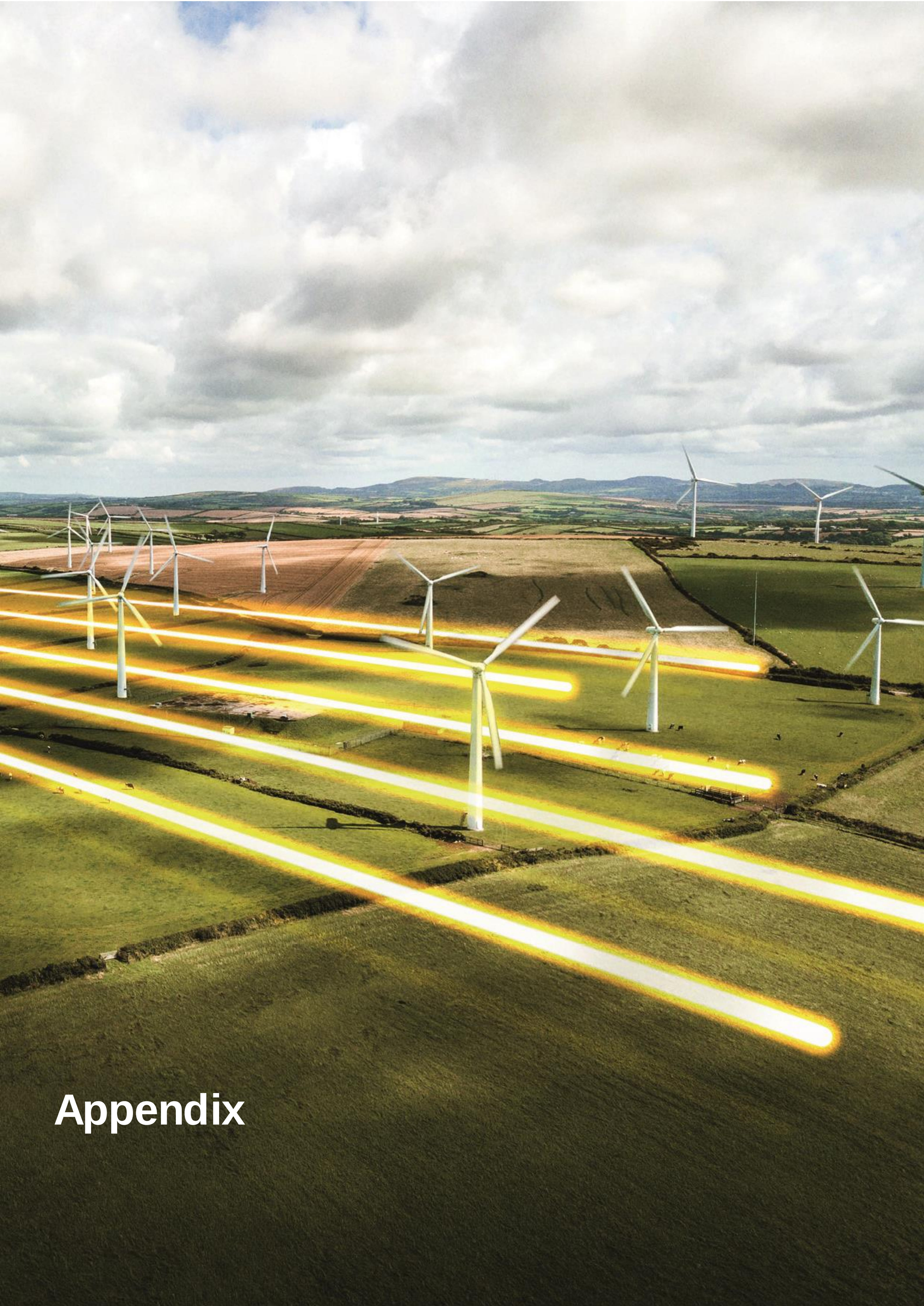
2. The Task Force have discussed how the recommendation on Deliverable 1) for Final Demand only to pay Balancing Services Charges could impact on large energy users and the potential for 'grid defection'. Do you think 'grid defection' is a possibility and to what extent would the Task Force's recommendations impact on your answer?



Just over half of the respondents did not believe that grid defection would occur as a result of the Task Force's recommendations whilst a fifth of respondents had no comment on this question. Some respondents cited an anticipated fall in wholesale prices as a reason for this view whilst others noted that achieving grid defection was in itself a challenge to achieve.

Some respondents also noted that they perceived the risk of offshoring to be greater than moving completely off grid and that the distributional impacts on energy intensive industrial users should be considered by the Task Force in making their recommendation on Deliverable 2. The Task Force created some case studies to explore the distributional impacts of both the volumetric and site-based charge methods. The Task Force agreed that the volumetric charge minimised distributional impacts and would be the least likely to prompt grid defection.

Grid defection was not a major consideration for the Task Force in making their recommendations as they believed that on the whole BSUoS charges were not going to be a major factor in the decision to offshore or invest in on site generation to go off-grid. The Task Force did acknowledge that a volumetric charge could encourage investment in solar panels or gas and diesel gensets, what could be considered as "partial grid defection". BSUoS is nonetheless a small component of the energy bill and on its own cannot (as the first Task Force concluded) send meaningful behavioural signals.



Appendix

Membership of the Task Force

As with the First Balancing Services Charges Task Force, an application process was opened to join the second iteration. Members were selected representing a broad range of expertise within the industry.

A full list of Task Force members is contained below:

Attendees	Company	Position
Colm Murphy	National Grid ESO	Chair
Joseph Henry	National Grid ESO	Technical Secretary
Jon Wisdom	National Grid ESO	Taskforce Member
Eleanor Horn	National Grid ESO	Secretariat
Andrew Rimmer	Engie	Taskforce Member
Lisa Waters	Waters Wye Associates	Taskforce Member
Tom Edwards	Cornwall Energy	Taskforce Member
Caroline Bragg	ADE	Taskforce Member
Olaf Islei	Shell Energy	Taskforce Member
Tom Steward	Good Energy	Taskforce Member
Joshua Logan	Drax Group	Taskforce Member
John Tindal	SSE Plc.	Taskforce Member
George Moran	Centrica	Taskforce Member
Simon Cowdroy	RES	Taskforce Member
George Douthwaite	Npower	Taskforce Member
Keith Munday	Bryte Energy	Taskforce Member
Paul Jones	Uniper	Taskforce Member
Joseph Underwood	Energy UK	Taskforce Member
Grace March	Sembcorp	Taskforce Member
Kayt Button/Lynda Carroll	Ofgem	Taskforce Member

Industry Engagement

The Second Balancing Services Task Force was launched by the ESO with its first meeting on 30th January 2020. This Final Report was submitted to Ofgem on the 30th September 2020. Task Force materials have been published on the Charging Futures website with a headline report and more detailed meeting summary available after each meeting. Alongside this, the Task Force members produced three short podcasts summarising the work undertaken during the first four months of the Task Force's work.

The Task Force took many opportunities to engage with industry throughout this period; to seek feedback and to raise awareness of the Task Force's preliminary conclusions. This feedback has informed the final conclusions of the Task Force throughout the development process.

It is also planned that the Task Force will also present its final recommendations at an upcoming Charging Futures Forum in Autumn 2020 (date TBC).

Date	Channel
18th December	Charging Futures Forum (Launch of TF)
30th January	Task Force Podcast
6th February	Transmission Charging Methodology Forum (TCMF)
6th February	Distribution Charging Methodology Development Group (DCMDG)
6th February	Renewable UK Open Conference Call
18th February	Renewable UK Open Conference Call
25th February	Task Force Podcast
5th March	Distribution Charging Methodology Development Group (DCMDG)
8th March	Energy Intensive Users Group (EIUG)
12th March	Charging Futures Forum (agenda item)
1st April	Task Force Podcast
2nd April	Distribution Charging Methodology Development Group (DCMDG)
2nd April	Transmission Charging Methodology Forum (TCMF)
8th April	Renewable UK Open Conference Call
7th May	Transmission Charging Methodology Forum (TCMF)
15th May	Distribution Charging Methodology Development Group (DCMDG)
2nd June	Distribution Charging Methodology Development Group (DCMDG)
4th June	Transmission Charging Methodology Forum (TCMF)
9th July	Transmission Charging Methodology Forum (TCMF)
20th July	Task Force Webinar: Interim Report and Consultation Update with Q&A
6th August	Distribution Charging Methodology Development Group (DCMDG)
11th August	Task Force Webinar: Mid Consultation Q&A session
3rd September	Transmission Charging Methodology Forum (TCMF)
3rd September	Distribution Charging Methodology Development Group (DCMDG)

Consultation Questions

The Task Force conducted a five week long consultation on the interim report from 22nd July 2020 – 26th August 2020. Respondents were invited to respond with their views on the following questions:

1. Do you agree with the Task Force's recommendations on <u>who</u> should pay Balancing Services Charges (Deliverable 1)? Please state your reasoning and evidence behind your answer.

2. The Task Force have discussed how the recommendation on Deliverable 1) for Final Demand only to pay Balancing Services Charges could impact on large energy users and the potential for 'grid defection'. Do you think 'grid defection' is a possibility and to what extent would the Task Force's recommendations impact on your answer?

3. Do you agree with the Task Force's recommendations that an ex ante fixed charge would deliver overall industry benefits? Please state your reasoning and evidence behind your answer.

4. How long do you think the fixed period should be and what in your opinion is the optimal notice period in advance of the fixed charge coming into effect? Please state your reasoning and evidence behind your answer.

5. Which approach discussed by the Task Force (TDR banded £/site/day or volumetric £/MWh) do you feel is most appropriate for Balancing Services Charges? Please consider your answer against the TCR principles and state your reasoning and evidence to support your answer.

6. The Task Force noted limitations of the approaches covered in Q5, what other methodologies or improvements to the ones in Q5 could you recommend to tackle them? Please consider your answer against the TCR principles and state your reasoning and evidence to support your answer.

7. Is 2 years' notice of the changes prior to an implementation date appropriate? Please state your reasoning and evidence behind your answer.

8. Should the Task Force consider any interim measures? Please provide details of any suggested interim solution including how it may deliver benefits to consumers or help to mitigate specific challenges facing market participants, whilst limiting any windfall gains or losses between industry participants.

9. Do you feel that there any interactions with the Supplier Price Cap that need to be considered? Please state your reasoning and evidence behind your answer.

10. The Task Force's initial recommendation is that Final Demand only will pay BSUoS. If this is the case, is the current RCRC mechanism is still appropriate? Please state your reasoning and evidence behind your answer.

11. Is there anything further you think the Task Force needs to consider?

List of Consultation Respondents

The 33 non-confidential respondents are listed in the below table with their industry type. For the purpose of graphs where responses are split by respondent type those marked with a * are listed as “Other”. The full responses are included in a zip file published alongside this final report on the Charging Futures website.

Organisation	Type of Industry Party
Tata Chemicals	EII
Mineral Products Association	EII
EDF	Vertically Integrated
Fred Olsen Renewables	Generator
EUIG	EII
ADE	Trade Body*
NGESO	System Operator*
Good Energy	Supplier
Renewable UK	Generator
Drax	Vertically Integrated
Energy UK	Trade Body*
VPI Immingham	Generator
Orsted	Vertically Integrated
RES	Generator
Red Rock Power	Generator
Sembcorp	Generator
Scottish Power	Vertically Integrated
Engie	Vertically Integrated
Eon	Supplier
Uniper	Generator
CI Biomass	Generator
Centrica	Supplier
Breedon	EII
ESB	Generator
SSE	Vertically Integrated
Intergen	Generator
National Grid Ventures	Developer*
Noriker	Supplier
Smartest	Supplier
Shell	Supplier
UK Steel	EII
RWE Innogy	Generator
ELEXON	ELEXON*

Alternative Banding Options – Pros & Cons

Due to the tight timescales the Task Force were unable to develop a complete alternative proposal to compare against a TDR banding option and a fixed volumetric approach. However, the Task Force still wanted to consider the potential merits and drawbacks of an alternative approach.

The below table shows some pros and cons for an undefined alternative banding approach.

TCR Principles	Fixed banding (different to TDR bands)	Pros & Cons
Reducing Harmful Distortions	Harder to avoid than volumetric charge	Pro
	Less reliant on historic set-up/can be reflective of customer rather than connection details (compared to TDR methodology)	
	different cliff-edges to TDR bands (reduced materiality of total fixed costs if at end of band)	
	administrative cost of keeping bands reflecting usage	Con
	More linked to system size than energy market which drives BSUoS costs (compared to volumetric)	
	Charging bands can create distortion e.g. Cliff edges leading to Grid defection, behavioural change to remain in certain band	
Fairness	Treats similar sized customers with different connections similarly (compared to TDR methodology)	Pro
	reduced incentive for partial grid defection	
	bands can be set up to take account of social issues such as fuel poverty, industrial strategy	
	Cliff edge can see very similar users charged very different amounts	Con
	grid defection impacts all users	
Practicality and Proportionality	Less information required from DNOs (dependant on nature of bands)	Pro
	bands could be made more flexible than every price control	
	Risk of overloading industry parties	Con
	Untested methodology could have unintended consequences	
	Require a disputes process	
	large distributional impact across end users	
	Would require new framework	
	similar-but-different framework could be confusing for end users and costly for suppliers	

Notes:

Bands could be set based on system usage each year with an appeals process

More frequent band adjustments could lead to higher costs to administer the methodology

Consumption/actual capacity would need to be averaged across a long period of time to avoid sending behavioural signals/disadvantaging seasonal users

Domestic Consumer Archetypes

These domestic consumer archetypes are from Ofgem's TCR impact analysis.

https://www.ofgem.gov.uk/system/files/docs/2020/05/ofgem_energy_consumer_archetypes_-_final_report_0.pdf

Table 1: Headline statistics and summary descriptions of energy consumer archetypes

Archetype		Numbers of hhlds	Heating fuel	Average hhld income (BHC) (GB avg: £34k)	Elec kWh (GB avg: 3,980)	Gas kWh (GB avg: 13,180)	Main attributes (key words)
A	A1	2,761,000	Mains gas	£48,000	3,250	9,650	High incomes, owner occupied, working age families, full time employment, low consumption, regular switchers.
	A2	2,916,000	Mains gas	£54,600	4,920	20,520	High incomes, owner occupied, middle aged adults, full time employment, big houses, very high consumption, solar PV, environmental concerns.
B	B3	3,674,000	Mains gas	£28,600	3,670	15,350	Average incomes, retired, owner occupied - no mortgage, electric vehicles, environmental concerns, lapsed switchers, late adopters.
	B4	2,323,000	Mains gas	£40,600	4,090	15,630	High incomes, owner occupied, part-type employed, high consumers, flexible lifestyles, environmental concerns.
C	C5	1,922,000	Mains gas	£15,200	2,570	11,270	Very low incomes, single female adult pensioners, non-switchers, prepayment meters, disconnected (no internet or smart phones).
D	D6	1,547,000	Mains gas	£18,100	3,920	12,340	Low income, disability, fuel debt, prepayment meter, disengaged, social housing, BME households, single parents.
	D7	1,205,000	Mains gas	£34,000	4,140	15,600	Middle aged to pensioners, full time work or retired, disability benefits, above average incomes, high consumers.
E	E8	2,356,000	Mains gas	£23,400	3,620	11,950	Low income, younger households, part-time work or unemployed, private or social renters, disengaged non-switchers.
	E9	3,093,000	Mains gas	£37,000	3,200	10,440	High income, young renters, full time employments, private renters, early adopters, smart phones.
F	F10	1,912,000	Oil, Electric	£38,900	5,750	0	Middle aged to pensioners, full time work or retired, owner occupied, higher incomes, oil heating, rural, environmental awareness, RHI installers, late adopters.
G	G11	1,510,000	Electric, Oil	£30,200	5,250	0	Younger couples/single adults, private renters, electric heating, employed, average incomes, early adopters, BME backgrounds, low engagement.
H	H12	644,000	Electric, Oil	£14,500	4,030	0	Elderly, single adults, very low income, medium electricity consumers, never-switched, disconnected, fuel debt.
	H13	526,000	Electric, Oil	£22,000	5,360	0	Off gas, low income, high electricity consumption, disability benefits, over 45s, low energy market engagement, late adopters.

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