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Consultation

Targeted charging review: minded to decision and draft impact assessment

Publication date:	28 November 2018	**Contact:**	Andrew Self
		Team:	Targeted Charging Review, Energy Systems Transition
Response deadline:	4 February 2019	**Tel:**	020 7901 7000
		Email:	TCR@Ofgem.gov.uk

We are consulting on changes to the way in which the costs of the electricity networks are recovered so that costs are shared fairly now and in the future. We are also consulting on removing some remaining distortions called "Embedded Benefits" which can increase costs for consumers and affect competition. We would like views from anyone with an interest in these charges and their wider impacts.

This document outlines the scope, purpose and questions of the consultation and how you can get involved. Once the consultation is closed, we will consider all responses. We want to be transparent in our consultations. We will publish the non-confidential responses we receive alongside a decision on next steps on our website at **Ofgem.gov.uk/consultations**. If you want your response – in whole or in part – to be considered confidential, please tell us in your response and explain why. Please clearly mark the parts of your response that you consider to be confidential, and, if possible, put the confidential material in separate appendices to your response.

Contents

1. Executive summary

This is a consultation on changes to the way in which we recover the costs of the networks used to transport electricity to homes, public organisations and businesses. These costs are recovered through two types of charges: 'forward-looking charges' which send signals about how much costs will increase (or decrease) with network usage, and 'residual charges' which recover the remainder of the costs. We want to ensure that these costs are shared fairly amongst all those who may want to use the electricity networks. We are undertaking a review of residual network charges and some of the remaining Embedded Benefits (discussed below) through the **Targeted Charging Review (TCR)**. This document sets out our proposals for this work.

The need for action comes from the changes in the energy sector. More and more businesses and households have their own generation in the form of solar panels or wind turbines or more traditional types of generation. Electricity storage is becoming more common and we are seeing increased take up of heat pumps and electric vehicles. The existing approach to reflecting the costs of the electricity networks in the charges people pay is becoming increasingly problematic. The rapid pace of changes in energy mean that the issues with the existing charging structure are likely to become worse over time. Ofgem is therefore taking action to address this and to ensure that network charging works in the interests of current and future consumers as a whole.

In July 2018, we consulted on a review of access arrangements to networks, how capacity is allocated and used and the forward-looking charges and the signals they give to those using the system. This review would aim to ensure that those who take action which benefits the electricity system and consumers as a whole pay less. This document focuses on the residual charges – charges which recover the remainder of the costs after the forward-looking network charges have been levied – and balancing charges to the extent they provide benefits to particular generators.

We are now consulting on two aspects of change: on the best way of setting the transmission and distribution residual charges; and on some of the remaining "Embedded Benefits" – which are different charging arrangements for smaller generators connected to the distribution system (called 'smaller embedded generators'), compared to larger generators. Both of these are covered by a Significant Code Review where we are establishing the basis for detailed changes to be made by the industry. We are consulting on the direction we will give to the industry next year.

On setting transmission and distribution residual charges, after significant analysis of different approaches, we consider that there are two leading options and we are consulting on these. They are:

- **A Fixed Charge**. Charges are set for individuals in customer segments, with these segments being based on an existing industry approach. **This is our preferred option.**
- **An Agreed Capacity Charge**. For those larger users who have a specified agreed capacity, a charge would be calculated directly. Capacity for households and smaller business would be based on assumed levels.

We have carried out a principle-led assessment, and have also carried out some modelling to support our assessment. This indicates a strong long-term case for reform of residual charges, with both of our leading options resulting in potential net system benefits to 2040 in the range of **£0.8bn to £3.2bn** and benefits to consumers as a whole in the range of **£0.5bn**

to £1.6bn.[1] In addition to the overall distributional effects, which saves the median domestic consumer £8, our proposed changes to residual charges could save around £2 a year for households in the longer term. This variation is dependent on views on the future. We have used National Grid's future energy scenarios for this work.

We explain our assessment of the impact of the options for reform in this document. Any change to network charges will have different effects on different types of consumer and rebalancing the allocation of these charges will inevitably means some people will pay more and some people will pay less. For the majority of consumers at present, charges are paid by retail suppliers who then decide how to pass costs on to end consumers.

The majority of households will benefit from the rebalancing of charges. However, some households who use the least electricity could face a typical annual increase of between £2 and £22 a year when these changes fully come into effect. Although this will be at least partially offset by the long term benefits of reform. The effect on businesses varies considerably. On average, domestic consumers would pay less than today; some firms may pay more, particularly if they have benefited from reduced contributions because of investing in on-site generation which has reduced their contribution to the existing system. Those that haven't taken such action pay less. Within the small non-domestic segment, the lowest consuming users will pay more than currently. Many of those facing an initial increase will benefit from the longer term savings from our proposed changes.

We are also consulting on implementation dates for these changes.

Our proposals on the remaining non-locational Embedded Benefits follow a process of reform which started with an open letter in July 2016[2]. We are consulting on timing and our detailed proposals to:

- Set the Transmission Generation Residual to zero, subject to maintaining compliance with the current cap on overall transmission charges to generators. This will remove a benefit to larger generators which receive a credit from these charges at present.

- Remove the Embedded Benefit relating to charging suppliers for balancing services on the basis of gross demand at the relevant grid supply point.

- Apply balancing services charges to smaller embedded generation.

- Implement these changes in 2020 or 2021.

- Launch a statutory consultation to extend the Small Generator Discount from the current end date of 31 March 2019 to a revised end date of 31 March 2021, with the intention that this will be set to zero once the changes set out above are implemented.

- Consider the conclusions from a task force on balancing charges and decide if other changes to balancing charges should be taken forward in parallel with or subsequently to our proposed changes.

[1] These values represent Full Reform Scenarios
[2] https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter_-_charging_arrangments_for_embedded_generation.pdf

Our proposed changes to Embedded Benefits could save around £7 a year for households. Our leading options reduce consumer costs (by between £4.5bn to £6bn for TGR & Full BSUoS reform, and by £3.3bn to £4.1bn for TGR & Partial BSUoS reform). However there will be only small impacts on system costs (from a reduction of £0.11bn to an increase of £0.16bn). We welcome your views on these proposals by **4 February 2019**. We will consider the views and evidence provided in response to this consultation before deciding on the direction we will give to the industry under the SCR process. We currently plan to make this decision by mid-2019.

2. Context

Introduction

2.1. The way we charge for the use of the electricity networks needs reform. While Project Transmit[3] was a major review of the forward-looking transmission charging arrangements, the other arrangements haven't been subject to a similar holistic review for a number of years.

2.2. Our energy system is undergoing a radical transformation. We are generating and using electricity in different ways, in different locations and at different times. Historically, consumers have been seen as largely passive participants in the energy markets. Total consumer demand at any point in time has been seen as mostly "fixed" and generators such as coal and gas powered plants have been the "flexible" part of the system, adjusting generation output to meet demand. As the electricity system decarbonises, this means there is increasing amounts of intermittent renewable generation sources for which the generation output is less flexible as it depends on when the sun is shining and the wind is blowing. This means that, increasingly, we need more flexibility in the electricity system. New technologies and decreasing technology costs of smart meters, solar photovoltaics (PV), batteries, electric vehicles (EVs) and similar technologies are key enablers for this flexibility.

2.3. Our recent work on a strategy for regulating the future energy system[4], the Smart Systems and Flexibility plan[5] we produced with government, and our consultation on reforms to arrangements for electricity network access and forward-looking charges[6] outlined why our current regulatory framework requires reform.

2.4. Flexibility is important where it helps to balance the supply and demand for electricity and helps to ensure electricity prices are no more than necessary for a safe and reliable electricity grid. There are however ongoing costs of the grid which remain and which have to be recovered. It is important that users benefitting from the network infrastructure are contributing fairly towards its operation and upkeep and that these costs are not simply falling on those least able to respond. All users benefit from being connected to the networks, through the sharing of assets and the lower costs that economies of scale provide. The networks enable users to access reliable generation, demand and services that would otherwise be more expensive to provide on a standalone basis to individual sites.

2.5. Ongoing electricity network charges for using the system have two elements. The first is forward looking charges that are designed to ensure network users (via suppliers for many customers) receive signals that reflect the costs of how and when they use electricity, which can encourage users to be flexible in their use in order to reduce their own electricity bills and reduce network costs overall for the benefit of all users. The second element is residual charges. These are designed to ensure that network costs not recovered from the forward-looking charges are fully recovered. These charges should be designed to minimise distortion to the forward-looking signals. The total

[3] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/project-transmit
[4] https://www.ofgem.gov.uk/publications-and-updates/our-strategy-regulating-future-energy-system
[5] https://www.ofgem.gov.uk/publications-and-updates/upgrading-our-energy-system-smart-systems-and-flexibility-plan
[6] https://www.ofgem.gov.uk/publications-and-updates/getting-more-out-our-electricity-networks-through-reforming-access-and-forward-looking-charging-arrangements

costs to be recovered are determined through the price controls, which set the total revenue the network companies are allowed to earn while ensuring the overall costs of the network are kept as low as possible. This total revenue is then recovered through a combination of forward-looking and residual network charges.

2.6. Unlike forward-looking charges, residual charges are not intended to send signals or provide incentives to use networks in any particular way. However, if they are not well designed, these charges can incentivise behaviour that could lead to higher costs in future or unfair outcomes. Users can use on-site generation, demand side response (DSR) or storage to reduce the electricity they demand from the network when they believe their demand is being measured to calculate their charges. When a user responds to residual charge signals, they may reduce costs for themselves but don't reduce the total network costs that users need to fund collectively. The existing GB charging arrangements provide opportunities for some users to more easily avoid paying residual charges and increase the costs borne by others. If not addressed, this will lead to less efficient outcomes that are not in the best interests of consumers as a whole. Consumers who are less able to respond in ways which reduce their residual charges could end up paying a higher share of network costs.

2.7. Balancing System Use of System (BSUoS) charges recover the electricity system operator's costs of balancing the electricity system and largely function as a cost recovery charge at present[7]. When we launched the review, we indicated that we would consider the applicability of applying any wider TCR reform options to balancing changes. Since then, our Electricity Network Access Project has proposed a review of BSUoS (on which we will shortly be making a decision on whether to launch a Significant Code Review). We will consider the outcome of this work alongside responses to the proposed changes we are setting out in this document.

2.8. The TCR is focusing on how the residual element of charges are applied to users of the transmission and distribution networks, including storage. These charges amount to about £4bn/year. The TCR is also focusing on some of the other Embedded Benefits which remain after the removal of transmission demand residual payments to embedded generators.[8] The remaining locational Embedded Benefits are being considered through our work Electricity Network Access Project.

2.9. Residual charges are recovered from smaller users, such as households and small businesses, via per-unit consumption charges, and for larger users by a mix of per-unit consumption charges for distribution and peak demand charges for transmission, determined through a mechanism known as "Triad". The Triad system measures the consumption of electricity at three peak half-hour periods of use that are not disclosed to network users beforehand within a wider peak period. This approach strongly incentivises users to reduce their consumption of electricity from the networks in anticipation of these periods and to use on-site generation and storage instead.

2.10. These current arrangements encourage users who can afford to invest in on-site generation, Demand Side Response or storage to reduce their exposure to residual charges. Where this change in behaviour is in response to market prices or forward-

[7] BSUoS charges recover the total costs of balancing the system in each half hour and other system costs, and are generally difficult to anticipate, and hence provide limited forward-looking signals to network users on how they can affect their contribution to these charges.

[8] https://www.ofgem.gov.uk/publications-and-updates/embedded-benefits-impact-assessment-and-decision-industry-proposals-cmp264-and-cmp265-change-electricity-transmission-charging-arrangements-embedded-generators

looking charges, these activities are likely to be efficient. Where these activities are prompted by residual charge avoidance, they will not reduce costs for the system, and in some cases may add to them. These activities will also push residual charges up for other users. We do not think this this is a fair outcome – all users should contribute to the ongoing costs of the network infrastructure in exchange for the benefits it provides.

2.11. We expect that further growth in generating capacity at business premises, public bodies and homes is likely, sometimes referred to as 'behind the meter' or 'on-site' generation. National Grid's Future Energy Scenarios (FES) suggest the total installed capacity of generation on the system could more than double in the period up to 2040, and the level of microgeneration, which includes on-site generation and household solar PV, could increase more than tenfold.[9] Even if only a proportion of this increase in on-site generation were to arise, there would be significant impacts from these users not contributing in the same way to residual charges.

2.12. Residual charges are significant and make up 10-15% of a typical user's electricity bill.[10] The academic work in this area, including the MIT's Utility of the Future report, suggests that failing to adopt efficient ways to recover residual charges could eventually jeopardise network cost recovery entirely.[11]

The other Embedded Benefits

2.13. The scope of this Significant Code Review (SCR) includes the remaining non-locational 'Embedded Benefits'. The term 'Embedded Benefits' is used to describe the different charging arrangements for smaller (below 100MW) embedded generators (those connected to the distribution network) compared to larger generators. We approved a change to remove the largest of these, the transmission demand residual payment to smaller embedded generators, in our decision in June 2017. We have now undertaken a detailed assessment of the other Embedded Benefits. We think that further changes should be made to three elements: the transmission generation residual charge, the BSUoS payments received by smaller embedded generators from suppliers, and to ensure greater parity with larger generators, BSUoS charges should be paid by smaller embedded generators too.

2.14. This document sets out the background to this SCR, the steps we have taken to consider the possible reform options, the evidence we have gathered and modelling we have undertaken to investigate the potential impacts of the proposed changes. The following sections explain the process and evidence used to reach our 'minded to' position.

Storage

2.15. In the Smart Systems and Flexibility plan, we said some storage facilities were at a disadvantage to other types of generators and flexibility providers with respect to

[9] http://fes.nationalgrid.com/media/1363/fes-interactive-version-final.pdf
[10] Electricity bill based on consolidated segmental statements reported by the six larger energy companies in 2017
[11] Massachusetts Institute of Technology Energy Initiative produced a report which includes, among other things, discussion on the impacts of recovering residual charges http://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf

residual and BSUoS. When launching the SCR, we said that industry was best placed to undertake the analysis necessary to develop and implement reforms to the residual charges and balancing charges.[12] These modifications are underway and we are monitoring their progress carefully.

Links to other projects

2.16. *Electricity Network Access Project*: This project aims to improve the cost-reflectivity of forward-looking network charges, to provide users with more and better defined access rights, options for how they access the network, and to ensure that access to the system is allocated efficiently[13]. The TCR aims to reduce the level of distortion to the forward-looking charges, and hence aligns with the aims of the Electricity Network Access Project. Different approaches to valuing or allocating network access or setting forward-looking charges could affect the size of the residual charges in future. This is considered in the sensitivity analysis for the quantitative work supporting the TCR proposals.

2.17. Our consultation on Access Reform proposed setting up a BSUoS charges task force. Having analysed responses to that consultation, we have asked the Electricity Supply Operator (ESO) to launch a task force to provide analysis to support decisions on the future direction of BSUoS charges.[14] In particular, it will examine the potential and feasibility for some elements of BSUoS being made more cost-reflective and hence provide stronger forward-looking signals, and is due to report its findings in Spring 2019. On conclusion of this work, further consideration can be given to the treatment of any BSUoS charges which will remain principally cost recovery charges. We have therefore limited our consideration to options which remove the BSUoS Embedded Benefits without changing the overall structure of these charges.

2.18. *RIIO-2 Programme*: we set price controls for the system and network companies, which determine the amount of revenue that they can recover for providing network services to their customers[15]. The current set of price controls will end between 2021 and 2023 and the RIIO-2 programme is developing the new arrangements. We published our decision on the framework for RIIO-2 in July 2018. This outlined how RIIO-2 will address the transitioning energy sector and associated uncertainty and ensure that consumers receive the most cost-effective provision of network services. As our Electricity Network Access Project and TCR reforms take place, we will work to ensure that the price controls will ensure that consumers receive any network cost savings arising from more efficient price signals and improved recovery of residual charges.

2.19. *Half hourly settlement:* Market-wide electricity settlement reform can play a key role as the energy sector decarbonises and we move towards a smarter, more flexible energy system. In August, we published our outline business case[16]. In this document, we set out that the TCR and Access Reform work are looking to facilitate a smarter,

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[12] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-significant-code-review-launch

[13] https://www.ofgem.gov.uk/system/files/docs/2018/07/network_access_consultation_july_2018_-_final.pdf

[14] https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter_-_charging_arrangments_for_embedded_generation.pdf

[15] https://www.ofgem.gov.uk/network-regulation-riio-model/network-price-controls-2021-riio-2

[16] https://www.ofgem.gov.uk/system/files/docs/2018/08/marketwide_settlement_reform_outline_business_case.pdf

more flexible energy system, with users' impact on the network more accurately signalled and charged for, in order to incentivise behaviour that delivers a better outcome for the system and for consumers. Half Hourly Settlement (HHS) is a fundamental building block that is required to ensure that time-based price signals for network pricing are passed through to suppliers.

Next steps

2.20. We are consulting on the decision we are minded to take on the TCR SCR. We will consider all responses and evidence received by the closing date of 4 February 2019. Alongside this consultation, we are holding a Charging Futures Forum[17] in January 2019 to discuss the TCR and our Electricity Network Access Project.

2.21. The Charging Futures Forum (CFF) is a stakeholder forum we have set up which makes accessing information and providing feedback to our changes easier. The forum also helps facilitate co-ordination of changes to electricity connection and charging arrangements.

2.22. Following the above consultation, we expect to make a final decision on this review in mid-2019.

[17] http://www.chargingfutures.com/

3. Our approach

Section summary

This section describes the methods we used to assess the potential options for reforming current residual charging arrangements and certain Embedded Benefits. It provides an outline of the three TCR principles used throughout the assessment process. It then describes the analysis used to determine the quantitative impacts of different charging options for residual charging reform, including distributional, behavioural and wider systems analysis.

Qualitative assessment – option assessment against our principles

3.1. Throughout the TCR, three principles have guided our work, and we have referred to these as the 'TCR principles'. These were developed and refined through consultation with stakeholders who wanted us to ensure the principles had clear definitions. Overall, we must have regard to and act in accordance with our statutory duties - these principles help us achieve this when considering the issues. The TCR principles and how they apply to this work are outlined below. Our three principles are:

a) Reducing harmful distortions

b) Fairness

c) Proportionality and practical considerations.

3.2. Our principal objective is to protect the interests of existing and future energy consumers. This closely aligns with all three of our principles. Reducing harmful distortions protects consumers since anything which distorts wholesale markets and is likely to increase network costs impacts consumer prices in the short and long term. Fairness between end consumers of energy is an important aspect of protecting consumers. We also have responsibilities to ensure that industry participants are treated fairly (on legal and procedural grounds) and consistently, and that the markets in which electricity, and services for its production, are sold are functioning well is promoting effective competition. By having proportionality and practical considerations as a TCR principle, we can also ensure that we do not overburden energy market participants with new processes. We have been mindful of our environmental obligations and have formally assessed the carbon impacts of proposed reforms. In doing so we are trying to be fair, proportionate and practical.[18]

[18] We must assess and make a decision on TCR within the prescribed framework of the SCR process. Ultimately, if we direct an industry party to raise a modification proposal, our final decision on whether that proposal should be implemented will be based upon:
whether the proposal fulfils the achievement of the relevant objectives better, compared with current arrangements, and whether the proposal is consistent with our wider statutory objectives and duties, including those under European law.

Reducing harmful distortions

3.3. Through considering changes to existing arrangements, our aim is to reduce the harmful distortions caused by the current residual charging methodology which encourages some people and businesses to take measures to avoid residual charges.

3.4. We want to minimise the potential for (and impact of) any new distortions introduced as a result of changes to the residual charging arrangements. Any method of residual charging will lead to some distortions, but we want to reduce these as far as possible so that the energy system works efficiently and in the interests of consumers.

3.5. Residual charges that cause network users to adjust their investments or operational decisions are distortionary and can lead to inefficient use of the networks. Unless well-designed, they may also distort competition between different network users. As some network users avoid charges, this increases the charges to other network users, further distorting usage and investment.

3.6. Further details about reducing harmful distortions and our approach can be found in Annex 1.

Fairness

3.7. We think that all final demand users who benefit from the electricity network should pay towards its upkeep in a fair manner.[19] We have undertaken work to understand fairness and have engaged stakeholders and consumers to determine what they think fairness means in this context. We have also engaged with them to introduce and incorporate the concept of "energy justice"[20]. Further details of this engagement can be found in Annex 1.

3.8. Our work on fairness focused on the three elements we consider to apply most to electricity network charges. *Equality* and *equity* are both important concepts, but ones where there is likely to be some tension, as a charge cannot be both completely equal and equitable unless all users are very similar to one another. There are arguments for both qualities, and discussions with our consumer panel showed support for both equality and equity in charging arrangements[21]. We found that *need* was a difficult quality to incorporate into charging arrangements, but we noted that existing

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That final decision is taken in the light of a formal assessment by the modification panel. In order not to encroach upon the assessment of any potential modification proposal arising out of this SCR, we do not consider that it is appropriate at this stage for us formally to assess the various TCR proposals against the relevant objectives in this Impact Assessment. This Impact Assessment instead is focussed on performance of the proposals against criteria derived from our wider statutory objectives and duties, in the normal way.

[19] Final demand users are end consumers who use the electricity supplied by electricity networks, whereas storage facilities are intermediate users of electricity which stores electricity for later consumption.

[20] Energy Justice aims to provide all individuals, across all areas, with safe, affordable and sustainable energy.

[21] The consumer panels were made of consumers from four different parts of the country, further details can be found in Annex 2. Details about the panels and the results for their discussions can be found in the Revealing Reality Report 'Understanding Consumer's Views on Residual Network Charge'.

arrangements to safeguard vulnerable users would already go some way toward achieving this concept. In line with our statutory duties, we have undertaken a detailed analysis of the impact on financially vulnerable customers. More information on this can be found in section 3.

3.9. Through our work on fairness, we identified five elements of fairness that we considered most relevant to electricity network charging:

a) equity & equality;

b) simplicity;

c) transparency;

d) justifiability; and

e) predictability.

3.10. For this review, we consider 'fairness' both in the allocation of residual network charges overall and relative fairness in the trade-offs between the options we considered.

3.11. In line with our principal objective to protect the interests of existing and future energy consumers, we considered 'fairness' as it applies to, and among, end-consumers of electricity. We gave specific consideration to fairness with respect to residential and microbusiness consumers, and to consumers in vulnerable situations.[22] Further details regarding these components, how we developed our concept of fairness, and how we used this can be found in Annex 1.

Proportionality and practical considerations

3.12. We set out to be proportionate in our work and to consider the practical implications of any decision that we take as a result of the SCR. As with our other principles, we refined these assessment criteria through consultation with industry stakeholders and consumers. Further details about proportionality and practical considerations can be found in Annex 1.

3.13. Any decisions need to be proportionate to the issue being addressed, in this case the unfairness and the harmful distortions caused by the current residual charging arrangements. This means ensuring that any decision has a practical solution which does not impose an overly complex financial or administration burden on the electricity system and its users, or that is disproportionate to the benefits that the change brings for consumers.

3.14. We have considered how the options explored could be practically implemented, to ensure that any decision was also proportionate in this regard. We wanted to identify the steps in the charging process that might have to change to allow implementation,

22 A microbusiness employs fewer than 10 employees (or their full time equivalent) and has an annual turnover or balance sheet no greater than €2 million, or Consumers a lot more than 100,000 kWh of electricity per year, or Consumer not more than 293,000 kWh of gas per year.

so we could understand the proportionality and practicality of such a change, with the intention of reducing the burden on industry and stakeholders, as far as possible. We focused our assessment of practicality on the areas below, which then allowed us to qualitatively rank the policy options against each other:

a) Metering – the requirement to install new or /replace metering;

b) Data collection and processing – additional meter reads/collection/aggregation or the requirement to store/process the data in a different way;

c) Charge calculation – identifying where or how the relevant parties would have to change the charging methodology for residual charges. This could include changes to the methodology or models;

d) Billing systems – required changes to Distribution Network Operation (DNO)/Electricity System Operator (ESO) systems, as well as changes required to other stakeholder systems (eg Elexon or suppliers); and

e) Settlement – an assessment of whether and how the charging reform options would be reconciled for settlement purposes (if required).

3.15. We did not try to estimate the cost of implementing the policy options in detail. However, we used our practicality assessment to rank the different options against one another with the assumption that options which required greater changes to the categories above, were likely to lead to higher costs. Further explanation can be found in Annex 1.

Quantitative assessment – Analysis and modelling

This SCR has two components:

a) considering reform of residual charging for transmission and distribution, for both generation and demand, to ensure it meets the interests of consumers, both now and in future; and

b) reviewing the other 'Embedded Benefits' that may be distorting investment or dispatch decisions, and increasing costs to consumers.

3.16. For simplicity, we are reporting on the reform of residual charges and the remaining Embedded Benefits separately, although they are closely linked. As a result, the sections which discuss how we came to the our minded to decisions are separate, but the approach was very similar and the modelling described in the quantitative assessment part of this section applies to both residual charges and the Embedded Benefits.

3.17. The first step in our analysis was to understand the effects of the current arrangements on users' charges and the behaviours incentivised by them. We then sought to understand how these incentives change under potential alternative arrangements. Our analysis included:

a) the impacts of retaining the status quo;

b) the impact of change on individual users, across a broad range of sectors;

c) the likely distribution of charges across these users and the incentives that they face as a result of the signals provided by the cost-reflective charges; and

d) the impact of change on the most vulnerable users and on those large users for whom energy costs represent a significant level or who are most likely to have the ability and means to avoid these charges.

3.18. While the TCR principles outlined above have helped guide this work and provided an assessment framework, we also conducted and commissioned the following quantitative work:

a) distributional analysis: based on a static bill impact analysis of the effect of our options for reform on a range of representative domestic, commercial and industrial consumers;

b) behavioural analysis: assessment of the potential for behaviour to be affected in relation to how/when customers use the network, choose to use on-site generation and adopt new technologies, eg Electric Vehicles (EVs) and Heat Pumps (HPs);

c) wider systems impact analysis: system modelling of the implications for the costs of operating the electricity system and costs to consumers until 2040; and

d) research reports we are publishing with this decision.

3.19. We commissioned consultants and undertook various research for this project which provides the supplementary reports for this consultation including:

a) Frontier / LCP – Distributional and wider system impacts of residual charges;

b) Frontier / LCP - Wider System Impacts of Transmission Generation Residual (TGR) and Balancing System Use of Services (BSUoS) reform;

c) Revealing Reality – Understanding Consumer's Views on Residual Network Charges (consumer panels to consider consumer views on residual charges); and[23]

[23] The consumer panels were made up of consumers from four different parts of the country. Further details can be found in Annex 2. Details about the panels and the results for their discussions can be found in the Revealing Reality Report 'Understanding Consumer's Views on Residual Network Charge'.

d) TNEI and CEPA – International Review of Cost Recovery Issues (how residual charges have been implemented in other jurisdictions).

3.20. These supplementary documents are referenced throughout this report and helped us to reach our minded to position.

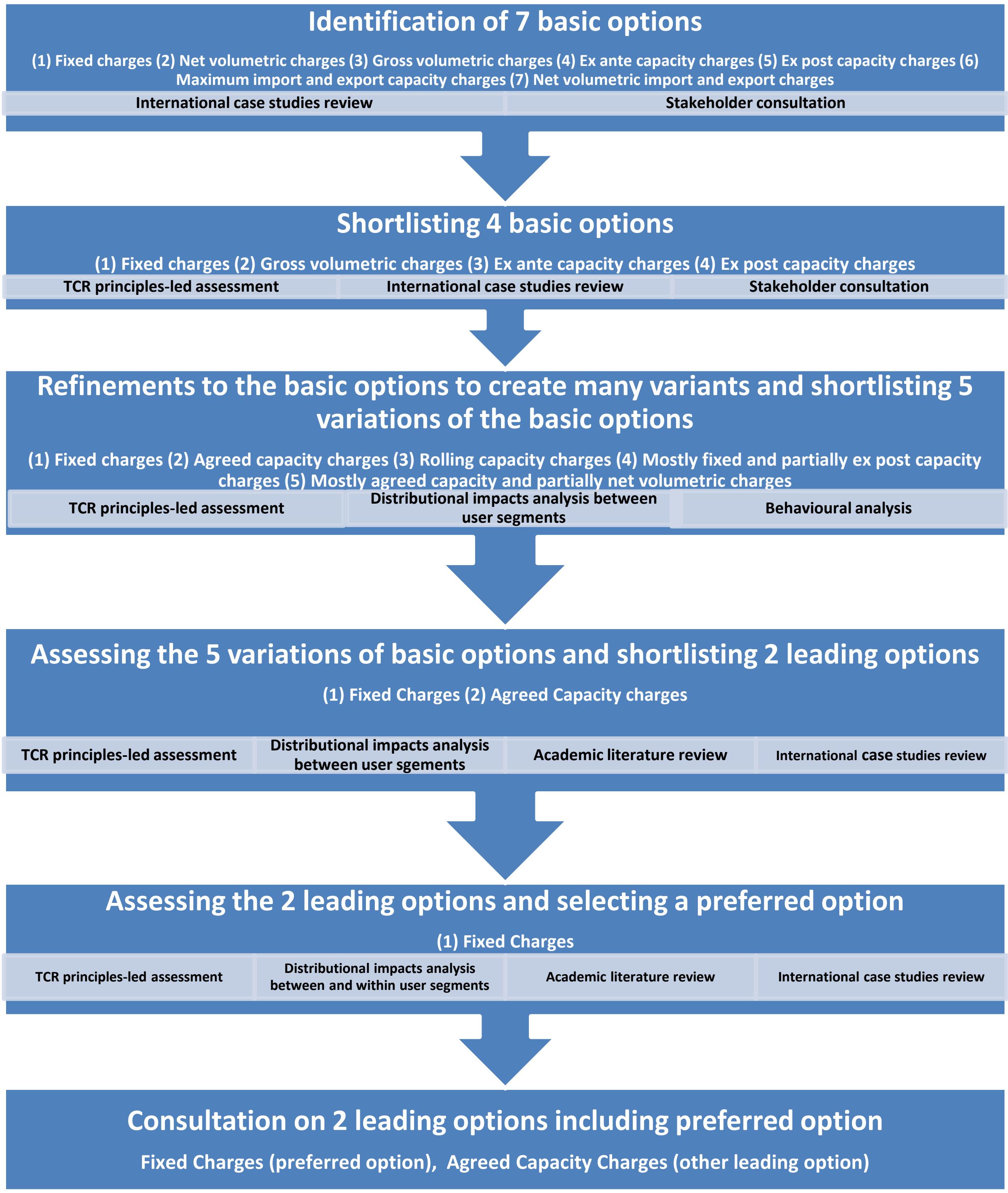
3.21. The relationship between this analysis and information from the supplementary reports and how they match the TCR principles we adopted at the start of this review can be seen in Table 1. This shows the type of work undertaken, which of our principles applied to that work and the evidence that it produced.

Table 1 Analysis, principles and evidence considered

Relevant Principles	Analysis Type	Evidence description
Fairness	Distributional Impacts	Modelling implications for a range of different representative domestic, commercial and industrial profiles, informed by public source data and information from stakeholders
	Stakeholders Annex Academic Research Annex	Literature Review, engaging with academics
	Annex 2 Stakeholders and research: consumer panel	Gathering consumer views on fairness via consumer panels
	Vulnerability Assessment	Assessment of impacts on vulnerable consumers
Proportionality and practical considerations	Distributional Impacts	Modelling implications for a range of different representative domestic, commercial and industrial profiles, informed by public source data and information from stakeholders
	Stakeholders Annex Academic Research Annex	Literature Review, engaging with stakeholders and academics
Reducing harmful distortions	Large Users Annex	Assessment of whether static impacts can lead to user behavioural changes
	Stakeholders Annex Academic Research Annex	Literature Review, Engaging with academics
	Stakeholders Annex Large Users Annex	Survey of large users
	Vulnerability Assessment	Assessment of impacts on vulnerable consumers
	Wider Systems Impact Analysis	Modelling of impacts on wider electricity system over time (dynamic assessment)

3.22. Figure 1 outlines the process followed to consider a wide range of potential options for residual charge reform and the number of options carried forward at each stage. The beginning of this process was the seven options from our working paper published in November 2017: Fixed charges, Gross volumetric charges, Ex-ante capacity charges, Ex-post capacity charges, Net volumetric import and export charges and Maximum import and export capacity charges.

Figure 1 Process to assess the options for residual charging reform



Remaining non-locational Embedded Benefits

3.23. The second part of this review has assessed the non-locational Embedded Benefits which were not covered in our 2017 decision (CMP 264/5). These Embedded Benefits relate to the transmission residual charges and BSUoS, and do not bear a relationship to the increased costs or savings from use of the network infrastructure.

3.24. Two of these Embedded Benefits relate to BSUoS charges and one relates to the transmission generation residual charge. Other Embedded Benefits were excluded because they are being considered through our Access reform or excluded due to their smaller scale. We explain this further in Annex 5.

3.25. We have applied the same three TCR principles (reducing distortions, fairness, and proportionality and practical considerations) to the assessment of the Embedded Benefits.

3.26. We quantitatively assessed the options through wider system analysis, using the same modelling framework as was used to assess reform of residual charges. This analysis sets out the impacts on the revenues and costs of different generation types, the potential behavioural changes of different generation types in the markets they participate in, and the overall combined impacts on system and consumer costs. Detailed distribution analysis (between customer types) was not undertaken in this case since the primary distributional impacts are for different types of generators.

4. How we reached the leading options

Section summary

First, this section summarises the previous analysis we published in our November 2017 update, by:

- Summarising our initial assessment on why we consider residual charges should be levied on final demand users only, and confirms that is our minded-to position for this consultation
- Outlining the four "basic options" for residual charges listed in our November 2017 update and explaining how we derived those four options

Second, this section outlines the new analysis we have undertaken since our November 2017 update, by:

- Explaining the long list of possible variants to the four basic options we developed which sought to address potential limitations of those basic options. From among that long list, we selected five variants which we considered were refinements on the four basic options.
- Outlining our assessment of those five variants against our TCR principles (reducing harmful distortions; fairness; practicality, proportionality and practical considerations).
- Explaining how we reached our two leading options of the Fixed Charge option and Agreed Capacity option, and why our preferred option is the Fixed Charge option.

Questions for consultation related to this section. Please provide evidence to support you answers.

1. Do you agree that residual charges should be levied on final demand only?

2. Do you agree with how we have assessed the impacts of the changes we have considered against the principles? If you disagree with our assessment, please provide evidence for your reasoning.

3. For each user, residual charges are currently based on the costs of the voltage level of the network to which a user is connected and the higher voltage levels of the network, but not from lower voltage levels below the user's connection. At this stage, we are not proposing changes to this aspect of the current arrangements. Are there other approaches that would better meet our TCR principles reducing harmful distortions, fairness and proportionality and practical considerations?

4. As explained in paragraphs 4.41, 4.43, 4.46, 4.49, 4.80, we think we should prioritise equality within charging segments and equity across all segments. Do you agree that it is fair for all users in the same segment to pay the same charge, and the manner in which we have set the segments? If not, do you know of another approach with available data which would address this issue? Please provide evidence to support your answer.

5. Do you agree that similar customers with and without on-site generation should pay the same residual charges? Should both types of users face the same residual charge for their Line Loss Factor Class (LLFC)?

6. Do you know of any reasons why the expected consumer benefits from our leading options might not materialise?

7. Do you agree that our leading options will be more practical to implement than other options?

8. Do you agree with the approaches set out for banding (either LLFC or deeming for agreed capacity)? If not please provide evidence as why different approaches to banding would better facilitate the TCR principles.

9. Do you agree that LLFCs are a sensible way to segment residual charges? If not, are there other existing classifications that should be considered in more detail?

Why we consider residual charges should be levied on final demand users only

4.1. In November 2017, we published a working paper which updated stakeholders on our (then) emerging thinking on who should pay residual charges and on the structure of those charges.[24]

[24] Ofgem, *Targeted Charging Review: Update on approach to reviewing residual charging arrangements*, November 2017.

4.2. In the working paper, we set out our initial assessment against our three TCR principles of whether residual charges should be levied on generators, final demand users, or a combination of the two. Our initial assessment was that residual charges should be levied on final demand users only. This is a change from the current arrangements where residual charges are levied on demand users, some generators (transmission connected generators, larger embedded generators and extra HV distribution connected generators) and storage facilities. Annex 8 of this minded to decision explains the current arrangements in more detail.

4.3. The following, Table 3 summarises our assessment why residual charges should be levied on final demand users only. Further detail can be found in our November 2017 update paper.[25]

Table 2 Assessment of whether generators, final demand users, or both should pay residual charges

TCR principle	Assessment	Reasons
Reducing harmful distortions	On balance, favours residual charges levied on final demand users, as there are potentially greater distortions if applied to generators	• Residual charges may distort both investment and operational decisions. These can include distortions to competition between different kinds (and scales) of generation and demand response. Examples of this might include additional investment that was not needed, or inefficient utilisation of existing assets. This is true for both generation and demand users of the network. • However, levying residual charges from generators can also distort outcomes between GB generators compared to interconnected generators, for whom residual charges are not levied. • There is also the potential distortion between grid-connected generators and on-site generators, as it may be difficult to levy the same residual charges on on-site generation.
Fairness	Does not favour one approach over the other	• As we would expect charges on generation to be largely passed through to demand users in the long run, from a fairness perspective we do not think there is a strong argument for residual charges to fall on either generation or demand users.
Proportionality and practical considerations	Favours either no change from current arrangements or residual charges levied on final demand users only	• At present the majority of residual charges fall on final demand users via their suppliers. Recovering all residual charges from final demand users would involve less change than setting a new generation/demand split for recovery. • At present, residual charges are levied only on some generators. Establishing a level playing field where residual charges were levied on all generators would pose a number of practical challenges including: establishing a framework for charging generators who are either not parties to the relevant industry code (CUSC) or are licence-exempt; addressing the competitiveness issues

[25] Ofgem, *Targeted Charging Review: Update on approach to reviewing residual charging arrangements*, November 2017.

		between GB and interconnector-connected generators.
Overall assessment	Overall assessment against the principles favours residual charged levied on final demand users only	

Source: Ofgem November 2017 TCR update

4.4. Our view that residual charges should be levied on final demand users appears to be supported by stakeholders. Since we outlined this position we have not received any substantive feedback from stakeholders disagreeing with this view.[26] Furthermore, no new information has come to light that would cause us to depart from our initial assessment. Accordingly, our minded-to decision is to maintain our view that residual charges should be levied on final demand users only.[27]

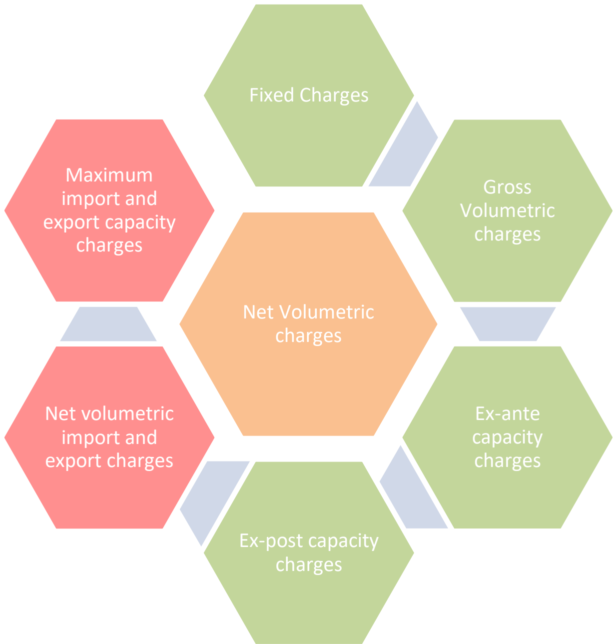
Our shortlisting from seven to four basic options

4.5. In our November 2017 working paper, we also identified seven basic options for setting residual charges. Following a high level assessment of these options against our three TCR principles, we proposed to take forward four of the basic options for a more in-depth assessment. The initial seven basic options are set out below.

[26] While we did not explicitly seek submissions from stakeholders on our November 2017 update, we have continued consulting with stakeholders through the Charging Futures Forum and through bilateral meetings. However, our publication of this minded-to decision presents a more formal opportunity for any stakeholder who does not agree with our position to levy residual charges on final demand users only to raise their concerns with us.

[27] In the November 2017 update, we flagged our (then) intention to conduct sensitivity testing as part of our qualitative modelling on the choice between levying residual charges on generators or demand users. Subsequent to that publication, we formed the view that the principles-led assessment was a sufficient basis on which to make this assessment. Consequently, the modelling we commissioned focused on other aspects of the TCR assessment.

Figure 2 Our shortlisting from seven initial to four basic options



4.6. Following a high level assessment of these options applying our principles, our key findings were:

a) Options that included separate charges for exported volumes or export capacity were seen as analogous to levying residual charges on generation, which would be inconsistent with our assessment that residual charges should be levied on final demand users only. Also, there are practicality issues with these options as the current metering technology for most users would not be capable of measuring the data needed to calculate these charges. For these reasons, we decided to not take forward the maximum import and export capacity charges or net volumetric import and export charges for further analysis.

b) Net volumetric charges (eg p/kWh) were seen to encourage behaviours that contribute to harmful distortions by allowing some users to reduce residual payments. CEPA and TNEI's review of international case studies found that many countries are moving away from recovering significant residual charges through volumetric charges for this reason (see Annex 3). We considered net volumetric charges would only be an option in combination with other charges. On that basis, our initial view is that that net volumetric charges would not be appropriate as the sole approach to recovering residual charges. Our recent review of the academic literature also strongly supports not using net volumetric charges as the primary means to recover residual charges (see Annex 3).

4.7. The remaining four options formed the starting point for our further analysis. We undertook work to initially define these basic options in order to assess the qualities of these options. These definitions are set out in the following table. (It is important to note that other approaches were subsequently identified, for example to move away from defining Fixed Charges by historic share).

Figure 3 Definition of the four basic options

Fixed charges	Gross volumetric charges	Ex-ante capacity charges	Ex-post capacity charges
• Initial approach set share of residual pot for each user segment based on historical contributions. • Same fixed charge for users within each user segment	• Per kWh charge based on all user's consumption (including from on- • site generation)	• Capacity charge based on individual customer agreed connection capacity, or on a deemed capacity where no explicit agreed capacity exists	• Charges are based on individual peak system usage, whenever this occurs in year

From four basic options to multiple variants from which we shortlisted five variants

4.8. For each of the four basis options, we identified the key challenges or weaknesses and identified possible variations to these options which could mitigate the impact of these key challenges. The key challenges and possibility variations are listed in the table below (*Table 3*).

Table 3 Key challenges of our four basic options and possible variations to mitigate these challenges

Basic option	Key challenges	Possible variation to mitigate challenge
Fixed charges (by historical volumes)	• Use of historical share (fixed at a point in time) • Use of historical share would not reflect changing use of the grid in the future	• Consider alternative ways to calculate fixed changes • Add a variable element or more user segments
Gross volumetric charges	• Current metering technology not capable of calculating charge for most users • Collection of 'behind-the-meter' data could be seen an invasion of privacy	• Restrict application to large users only
Ex-ante capacity charges	• Peak load (and capacity) reduction incentive to avoid residual charges • Missing data for some users • Same charge for different users • High distributional impact for domestic users	• Consider hybrid options with variable element • Deemed levels for some users

Ex-post capacity charges	• Individual peak load reduction incentive to avoid residual charges • Residual charge influences (distorts) operational decision • Current metering technology not capable of calculating charge for most users	• Consider hybrids options with fixed element • Deemed levels for users with basic meters

4.9. We identified a number of potential refinements which could apply to our basic options to improve them and mitigate the challenges we identified.[28] The refined options which we considered to merit further assessment are summarised in the following table (Table 4). We took the view that options that included arbitrary elements, or were inconsistent with the TCR principles would be discarded, and these are shown below in the red cells. Those in yellow cells were not considered to bring enough benefit to justify further assessment. The options in green cells were either taken forward, or were combined with others and taken forward, as they were considered to provide an improvement on the basic options.

Table 4 Refinements to the basic options and assessment for further investigation

Basic options	Possible refinement	Rationale
Fixed charges	Fixed with ex-post element	Differentiates users, links to system use
	Fixed with net kWh element	Differentiates users, links to system use
	Fixed by segment volumes	Links to system use, updates with time
	Fixed with charge caps	Limits disconnection risk
Gross Volumetric charges	Deemed Gross	Overcomes metering gaps
	Declining block rates[29]	Limits disconnection and redistribution
	Gross for wider user groups	Prevents boundary between user groups
Ex-ante capacity charges	Different deemed levels	Reduces redistribution from deemed capacity
	Domestic capacity bands	Differentiates users
	Declining block rates	Limits disconnection and redistribution
	Ex-ante with ex-post element	Differentiates users, links to system use
	Ex-ante with net kWh element	Differentiates users, links to system use
	Ex-ante set on ex-post usage	Links to system use, updates with time
	Fixed for basic metered users	Overcomes metering gaps

[28] Alongside this work, a number of other high level assessments were carried to consider whether further work was needed on the large number of possible combinations of charges that could be created using multiple part tariffs, using different combinations of allocations and recovery charges, as well as arrangements where different segments were charged in different ways.
[29] Declining block rates have lower charges for larger quantities. Inclining blocks have higher charges for larger quantities.

	Fixed with monthly ex-post	Less avoidable, links to consistent use of system
	Charge floors	Prevents charges falling below defined level
	Ex-ante set on ex-post usage	Links to system use, updates with time
Ex-post capacity charges	Deemed ex-post	Overcomes metering gaps

4.10. The options taken forward for further assessment are shown in the following Table 5. We included two hybrid options. These options consist mostly of one type of charge and partially of a different type of charge. As there is no clearly appropriate method to do this apportionment in a precise way, we weighted these options using the rounded numbers of 75% of one type of charge and 25% weight to the other type of charge.

Table 5 Our five variants of the basic options for further assessment

Fixed Charges (by net volume)	Agreed Capacity Charges (deemed for small users)	Rolling capacity charges	Mostly fixed and partially ex-post capacity charge	Mostly Agreed Capacity Charge and net partially volumetric charge
• Segments set by LLFC and revenue apportioned by net volume	• Using deemed levels for domestics and microbusiness, and agreed levels for medium and large businesses	• Ex-ante capacity level subject to rolling updates based on use of capacity	• Fixed Charges (75%) with monthly ex-post capacity (25%)	• Agreed Capacity Charge (75%) with volumetric element (25%)

4.11. We assessed these five variants options in detail. An assessment against our three TCR principles as well as a static distributional impacts analysis, behavioural analysis and wider systems analysis was carried out to understand their impacts and the consumer benefits that would be realised from their adoption. These assessments are shown in more detail in Annex 4 and the Frontier 'Wider system impacts of TGR and BSUoS reforms' report.

4.12. A summary of our assessment of these five options against each of the three TCR principles and the distribution impacts analysis is included below in Table 6. Below that table is a detailed fairness assessment of each of the five options in Table 7.

4.13. We found that Fixed Charges and Agreed Capacity Charges were most likely to further the TCR principles. This is because both options scored well against our reducing harmful distortions principles and the distributional impacts analysis. The Fixed Charge option also scored well against the proportionality and practical considerations principles, whilst both the Agreed Capacity Charges and Fixed Charge option scored well against the fairness principle. The Agreed Capacity Charge scored moderately well on the proportionality and practical considerations principle. Neither option scored poorly against any of the principles or the distributional impacts analysis.

4.14. We also considered an option of mostly Agreed Capacity charges (75%) and partially net volumetric charges (25%) was also attractive and had a reduced impact on lower consumption users, as well as differentiating between similar users who use different volumes of electricity. However, we were concerned this would retain a moderately significant distortion to efficient price signals as the volumetric component could be avoided by some users.

Table 6 Assessment of the five options against our TCR principles and against distribution impacts

Shortlisted five variants of basic options	Reducing harmful distortions	Fairness	Proportionality and practical considerations	Distributional impacts
Fixed Charges (set by net volume and LLFC)	• Removes existing distortions and introduces no significant new distortions • There is broad support in the academic literature for fixed charges as a means to recover residual charges in a manner which reduces distortions to efficient price signals (see Annex 3) • International experience suggests a number of jurisdictions are adopting more fixed-type charges to address the issues of distortion, with some jurisdictions in the USA, Australia and Italy providing examples of countries which are moving towards recovering a greater proportion of residual charges from fixed charges (see Annex 3). • Most significant distortion is the risk of grid defection. However this risk is not considered to be significant in the near future given high cost of providing standalone supply that provides high levels of reliability	• Use of different charges for smaller and larger user groups provides equitable recovery of costs across segments • Quite equitable as based on a fixed amount where all alike users within segments pay the same charge. • Predictable, stable, simple charges all contribute to improved perception of fairness • Some academic literature notes using fixed charges to recover all residual charges may create perception of unfairness in some cases (due to distributional impact) • Some attendees of our consumer focus groups felt that charges that were the same for all were fairer if they reflected something we all benefit from • Using aggregated volumes to apportion to user segments may improve the justifiability of charges	• Uses existing industry arrangements • Measurement of net volumes can be calculated using existing metering technology, and unmetered volumes well understood • No new metering or data requirements would be expected to be needed • Possible requirement for greater granularity for segmentation at extra high voltage and transmission level • No privacy concerns expected	• Low distributional impact between user segments as volumes make significant contribution to current allocations • Low users will see increased charges relative to their segment averages • Some distributional impact within segments as the same charge is used for all users with a Line Loss Factor Class those who use lower volumes will see increased charges, and those with higher volumes will see reduced charges.
Agreed Capacity charge (deemed capacity for small users)	• Removes most existing harmful distortions • There is some support in the academic literature for capacity charges as a means to recover residual charges in a manner which reduces distortions to efficient price signals (see Annex 3) • For medium and large businesses - introduces an incentive (distortion) to reduce agreed capacity level to reduce contribution towards residual charge recovery • For domestic users and microbusinesses - capacity levels would need to be deemed because of lack of widespread explicit capacity agreements. This means it would have similar properties as fixed charges for these users • International experience suggests a number of jurisdictions are adopting capacity charges to address the issues of distortion, with the Netherlands, Spain and Italy providing examples of countries which are moving towards capacity charges	• Higher equity as more graduated charges for domestic user than our Fixed Charge option, which relates to capacity and so may be seen as fairer by some users. • Some attendees of our focus group felt that charges more linked to use were fairer • Charges relate to size of user where consumers have agreed capacity levels, which may be seen as more equitable • Capacity link to use of the system may improve the justifiability of charges	• Agreed Capacity levels use existing industry arrangements • Arrangements would need to be developed to manage deemed capacity values for domestic users which means that fixed charges would achieve the same outcome • Use of net volumes for domestic bands is available now and in use. • No new metering expected to be required • No privacy impacts expected if use deemed domestic capacity bands	• Low distributional impact between segments with exception of low voltage non-domestic users • Low users will see increased charge relative to their segment averages • Little distributional impact as charges relate to size of user where consumers have agreed capacity levels. •

Rolling ex ante capacity charges	• Having a rolling ex-post capacity measure means distortions are reduced, but reducing contribution towards residual charge recovery is still possible for users who invest in onsite generation and other means to reduce the peaks in their use of the grid • Capacity levels would need to be deemed for small users because of lack of widespread smart metering. This means it would have similar properties as fixed charges for these users.	• Some attendees to our focus group felt that charges more linked to use were fairer. • Charges relate to size of user where consumers have agreed capacity levels, which may be seen as more equitable • Capacity link to use of the system may improve the justifiability of charges	• The provision of ex-post and individual billing likely to require major system changes for multiple stakeholders • Half Hourly metering required for the excess capacity charge and not feasible for NHH users • Ex-post charges difficult if a user moves supplier mid-year • Likely requirement to store the data centrally for this to be avoided • Some privacy considerations depending on who requires access to the data	• Distributional analysis suggests large redistribution of charges - domestic users and those with high peak use will pay significantly higher share of residual charges •
Mostly fixed (75%) and partially ex-post capacity charge (25%)	• Significant fixed charge portion removes much of existing distortions • Ex-post capacity element remains avoidable by some users • Capacity levels would need to be deemed for small users because of lack of explicit capacity agreements and widespread smart metering. This means it would have similar properties as fixed charges for these users	• As the capacity element of the charge may need to be deemed for small users, it is essentially a fixed charge • For non-deemed users, more equitable as adds individual use to a fixed charge. • Complex multi-part charge and relates to a reasonably complex measure of capacity • The percentage split relies on a regulatory decision • Justified to base a charge on a monthly peak	• Ex-post charging for domestics poses practicality challenges. • Ex-post element requires major system changes if using individual billing • Likely requirement to store the data centrally • Half Hourly metering required for the ex-post element, if determined on a single/multiple peak • The provision of ex-post and individual billing likely to require major system changes for multiple stakeholders	• Distributional analysis suggests that domestic users and those with high peak use will pay higher share of residual charges • Users with high peak capacity will pay more
Mostly agreed capacity (75%) and partially net volumetric charge (25%)	• Significant agreed capacity element removes some of the existing distortions • Introduces incentive to reduce agreed capacity level for users with these types of connection. • For medium and large businesses - introduces an incentive (distortion) to reduce agreed capacity level to lower contribution towards residual charge recovery • For domestic users and microbusinesses - capacity levels would need to be deemed because of lack of explicit capacity agreements and widespread smart metering. This means it would have similar properties as fixed charges for these users • For all users - retains moderately significant incentive (distortion) to reduce the amount of electricity they import from the grid, due to the net volumetric element of the charge • International experience suggests a number of jurisdictions are adopting capacity charges, but often moving away from volumetric charges.	• Higher equity due to deeming based on volume. Equitable as costs are allocated through a capacity based charge that reflects different user size. • Additional equity from volumetric element • Deemed levels may not be as transparent as other options, as there may not be a direct link between volumes (that set the deemed bands) and actual use of capacity. • This charge is relatively complex in its nature, as deemed bands are set by volumes for some users or at defined levels for others while agreed capacity is used for others • Some academic support for partial use of net volumetric charges in combination with fixed (and/or capacity) charges are a means to reduce the distributional impacts of these other approaches. • The split of having a multi part tariff is complex so reduces transparency. Whilst the split itself is a regulatory decision.	• Agreed Capacity levels could use the existing industry arrangements for larger users • Arrangements would need to be developed to manage deemed capacity values for domestic users which means that fixed charges would achieve the same outcome • The use of net volumes for domestic bands is available now and in use • No new metering expected to be required • No privacy impacts expected if use deemed domestic capacity bands	• Lower distributional changes than standard Agreed Capacity charge • Large users pay more due to higher volumes used

Table 7 Detailed assessment of five options against our fairness principle

Options	Simplicity	Transparency	Justifiability	Equity and equality	Predictability	Overall
Weighting	**High**	**Medium**	**Medium**	**High**	**Medium**	
Definition	*How easy it is to understand from a user's point of view. Includes as fewer elements.*	*Moving parts are linked to justification*	*Link to features of the system or to the individual segment use of the system*	*The differentiation between different users*	*The ability to forecast, reasonable certainty of what charge should look like.*	
Fixed Charges (set by net volume and LLFC)	**Very simple** Single element to the charge based on a single piece of information, the volume used by a segment. Volume is well understood by users already. The charge is not complex and should be easy for users to understand.	**Very transparent** Transparent in its nature as is based upon segment usage rather than being based on any historic level. Measurable system quantity and relatively simple methodology.	**Very justified** Charges set are based on actual usage.	**Quite equitable** Quite equitable as based on a fixed amount where all users within segments pay the same charge	**Very predictable** The charge should be predictable as system and sector volumes are likely to change relatively gradually, and so should be forecastable. Fixed charges are predictable in nature.	**Fairest option on balance**
Agreed Capacity charge (deemed capacity for small users)	**Quite simple** Based on a capacity charge with deemed domestic assumption. . Not simple for having differing charges for smaller and larger users. Simple for domestic user as a deemed amount.	**Quite transparent** Deemed levels may not be that transparent, as there may not be a direct link between volumes (that set the deemed bands) and actual use of capacity.	**Quite justified.** The deemed levels are a compromise between simplicity and accuracy as metering capability isn't present for many users.	**Very equitable** Equitable as costs are allocated through a capacity based charge that reflects different user size. Reflects different use within segments as well as across segments.	**Quite predictable** Quite predictable as the residual will be assumed at the deemed level for domestic consumers. This should allow some degree of forecastability. Deemed band set on volumes which are well understood.	**More complex but fair elements**
Rolling ex ante capacity charges	**Quite simple** Simple to understand as calculated by reference to users' capacity but also updated with actual use. Charge is more complex in its nature	**Quite transparent** Transparent in nature. However, domestic users are unlikely to know peak demand, so less transparent than the fixed demand charge based on historic levels	**Quite justified** Charge based on user's capacity.	**Very equitable** Based on individual use.	**Quite predictable** Would be quite predictable (despite being a more complex multi part charge) if users use the system the same way each year but may vary if use or behaviour changes considerably.	**Fair**
Mostly fixed (75%) and partially ex-post capacity charge (25%)	**Not simple** Complex as is a multi-part charge and relates to a reasonably complex measure of capacity. Part of charge is based on users capacity. Charge has a number of measurement periods.	**Not transparent** Not transparent as a is a multi-part charge and at present many domestic users may not be familiar with their actual peak demand.	**Not justified** Percentage split is arbitrary.	**Quite equitable** Adds individual use to a fixed charge.	Overall for billing charges are **quite predictable** but are dependent on consumption The fixed element is **very predictable** and will remain the same, though the monthly usage may change.	**Less transparent, complex, less fair**

Mostly agreed capacity (75%) and partially net volumetric charge (25%)	**Not simple** based on a capacity charge with deemed domestic assumption that may not relate to actual use. This charge is quite complex in its nature, as deemed bands are set by volumes for some users or at defined levels for others while agreed capacity is used for others. Additional volumetric element will add complexity.	**Quite transparent** Deemed levels may not be that transparent, as there may not be a direct link between volumes (that set the deemed bands) and actual use of capacity.	**Quite justified** The deemed levels re a compromise between simplicity and accuracy as metering capability isn't present for many users. Unjustified arbitrary split.	**Very equitable** Equitable as costs are allocated through a capacity based charge that reflects different user size. Reflects different use within segments as well as across segments Additional volumetric element will add equity.	**Quite predictable** Quite predictable as is based on historic capacity, so charges should not vary much from those faced by the user previously and the rolling period will reduce volatility.	**More complex still but fair elements**

Detailed assessment of the two leading options

4.15. We first set out a more detailed description of our two leading options. We then assess each of those options using our qualitative assessment against our principles and our quantitative assessment through the modelling analysis.

4.16. The two leading options for consideration are:

a) **Fixed Charges**. These would be set using an existing industry mechanism for customer segments, with charges for each segment based on metered consumption volumes (on a net basis) for that segment. There is a strong theoretical basis for fixed charges, as they cannot be easily avoided other than by disconnecting from the grid.

b) **Agreed Capacity Charges.** These would be assumed or "deemed" for households and microbusinesses and based on specified capacity levels for other customers (potentially on the basis described later in this section). They allow for greater differentiation between types of consumer (particularly at domestic, extra high voltage and transmission level, and so have fewer step-changes in charges for different groups. However, as they are based on capacity, there could still be some scope to take action to reduce contribution to residual charges.

4.17. The Fixed Charges option allocates the total residual charging pot by customer segments, based on the total net volume used by that segment. We consider this way of setting fixed charges is justifiable and prevents individual users taking action to lower their contribution to the residual charge. After engagement with our consultants and industry participants, we chose Line Loss Factor Classes as our method of segmenting users. This is an existing method in wide use which groups together similar types of consumers and is currently used for allocating network losses.[30]

4.18. Fixed Charges (for a single DNO area) are applied based on which Line Loss Factor class a user sits in, splitting consumers into groups. For example:

a) all single rate domestic consumers will pay the same fixed charge for using the network;

b) all Economy 7 customers face a different fixed charge; and

c) all single rate small non-domestic consumers face a different fixed charge.

4.19. The key remaining challenge with this option are the boundary effects created by segmentation. There are step changes in the residual charges paid for each segment, and no variation within the segment. Movement between segments would only be possible if the Line Loss Factor Class is changed for that user, as each user is assigned a Line Loss Factor Class.

[30] Line Loss Factor Classes are a collection of metering systems with the same Line Loss Factors (LLFs) and shared characteristics, with the LLFs indicating the user's location on the network and metering characteristics.

4.20. The Agreed Capacity option uses a measure – agreed capacity – which is the amount of capacity that a user holds as set out in the agreements they have with their network operator to access the system. Where these agreements are not explicitly in place, such as for smaller non-domestic users and for households, a 'deemed' or assumed value would be used. Line Loss Factor Classes are not used for this, instead, consumers are grouped by assumed levels of agreed capacity. Domestic users are separated out from non-domestic users using LLFCs, though for non-domestic users only the level of agreed capacity that a user holds is needed. Where this does not exist, as is the case for smaller users, a deemed capacity value is used. For the purposes of our modelling, we have used the following indicative bands:

a) 4kVA for most domestic customers (75 per cent of all domestic customers)

b) 6kVA for 'higher consuming' domestic customers (assumed to be 15% of all domestic customers)

c) 8kVA for users with electric vehicles or heat pumps (assumed to be 10% of all domestic customers)

4.21. We anticipate that industry working groups could take forward the role of establishing these bands, based either on our proposals, or other bands which achieve the TCR principles and are consistent with the considerations set out in this document.

4.22. The key remaining challenges with the Agreed Capacity option are that large users can still respond to the residual charge by reducing their capacity agreement, especially new users who have not set up a capacity agreement yet, which may still lead to charges being shifted on to other users. Having deemed capacity bands also means step changes between user groups for smaller users.

4.23. Under both of our leading options, our intention is that the methodologies would be calculated such that residual revenues would be recovered by applying residual charges to users based on the voltage level at which they are connected. Distribution-connected network users would also pay transmission residual charges, in line with current practice. Transmission-connected network users do not pay distribution residual charges. This is because, at present, we have not identified a strong case for moving away from this aspect of the current arrangements. The current approach is also aligned with other jurisdictions. We seek stakeholder views on whether this aspect of the current arrangements remains appropriate, or if there are alternative approaches that would better promote our TCR principles.

Principles based assessment of the leading options to identified a preferred option for consultation

4.24. In order to identify a preferred option from our two leading options, we assessed each option against the TCR principles, with a summary of this analysis set out in Table 6 above. Below we set out our assessment of our two leading options.

Reducing Distortions

4.25. **Fixed Charges**. We consider fixed charges to be the most effective means of reducing the existing distortions to residual charges, and do not consider them to introduce significant new distortions, with the key remaining distortion, physical disconnections from the network, a risk which we assess as low. The general approach is well supported in the academic literature. Further, international experience suggests a number of jurisdictions are adopting more fixed-type charges to address the issues of residual charge distortion, with the USA, Australia and Italy providing examples of countries which are moving towards recovering a greater proportion of residual charges from fixed charges. See Annex 3 for more details on the academic literature and international case studies we reviewed.

4.26. **Agreed Capacity Charges** effectively reduce the harmful distortions that we are concerned about. However, our leading option introduces incentives to reduce agreed capacity level for users with these types of connection. The need to set deemed levels for domestic consumers also introduces further distortions to reduce net volumes from the network. Like our Fixed Charges option, Agreed Capacity charges are well supported by academic and international experiences including in the Netherlands, Spain and Italy.

Fairness

4.27. **Fixed Charges.** The use of different charges for smaller and larger user groups provides equitable charges across segments, although a single charge within segments may be considered to be less equitable where there is significant range of users within segment. The reduction in equity may be perceived by some consumers as less fair than other options, but the improvement in equality (resulting from users with similar call on the system paying the same) improves fairness. We have also carefully considered the distributional impacts of moving to fixed charges. Our evidence indicates that the predictable, simple charges resulting from this option contribute to improved perceptions of fairness. Further, the volume linkage to use of the system improves the justifiability of charges from the status quo and versus other options.

4.28. **Agreed Capacity Charges**. Linking charges to agreed capacity leads to some instances of higher equity than fixed charges as this provides more graduated charges for domestic users than our Fixed Charge option. It also relates to usage and be seen as fairer by some users. Capacity link to use of the system may improve the justifiability of charges.

Proportionality and Practical Considerations

4.29. **Fixed Charges**. Our leading option uses existing industry arrangements and no new metering or data would be expected to be needed. The use of net volumes is near universal across industry, and unmetered volumes are well understood. We are nonetheless keen to understand possible requirements for greater granularity for segmentation at extra-high voltage and transmission level.

4.30. **Agreed Capacity.** As with our other leading option, Agreed Capacity Charges use existing industry arrangements and data. However, arrangements would need to be developed to manage deemed capacity values for domestic users.

4.31. Overall**,** our minded to view is that the Fixed Charges option best meets our TCR principles overall. We consider both options would effectively address our reducing harmful distortions principle, though the Fixed Charges option may be more effective with respect to large users. And we consider our Fixed Charges option, on balance, would more effectively address our fairness principle and our proportionality and practicality considerations principle.

The Options

4.32. A brief overview of our leading options can be found in Figure 4 Leading option definition.

Figure 4 Leading option definition

<table>
<tr><th>Option</th><th>Justification</th><th colspan="2">Allocation approach</th><th colspan="2">Charge basis</th></tr>
<tr><td rowspan="2">A) Fixed
Fixed charge is calculated for each user segment, defined by Line Loss Factor Classes. The allocation between segments is based on total segment metered volume (net).</td><td rowspan="2">There is a strong theoretical underpinning for fixed charges Allocation is based on an easily measurable quantity, and updates annually for segments.</td><td>Small users</td><td rowspan="2">Allocated based on net volumes in segment.</td><td>Small users</td><td rowspan="2">Fixed charge</td></tr>
<tr><td>Large users</td><td>Large users</td></tr>
<tr><td rowspan="2">B) Agreed capacity
For those larger users which have agreed capacity, a charge is calculated directly. Deemed capacities are set for domestics and smaller non-domestics.</td><td rowspan="2">Ex ante capacity charges for larger users allow for more differentiation and fewer boundary effects. Reduces distributional impact by deeming capacity for small users.</td><td>Small users</td><td>Allocated based on deemed capacities, with bands for domestics and</td><td>Small users</td><td>Fixed charge</td></tr>
<tr><td>Large users</td><td>Allocated based on agreed capacities.</td><td>Large users</td><td>Agreed capacity charge</td></tr>
</table>

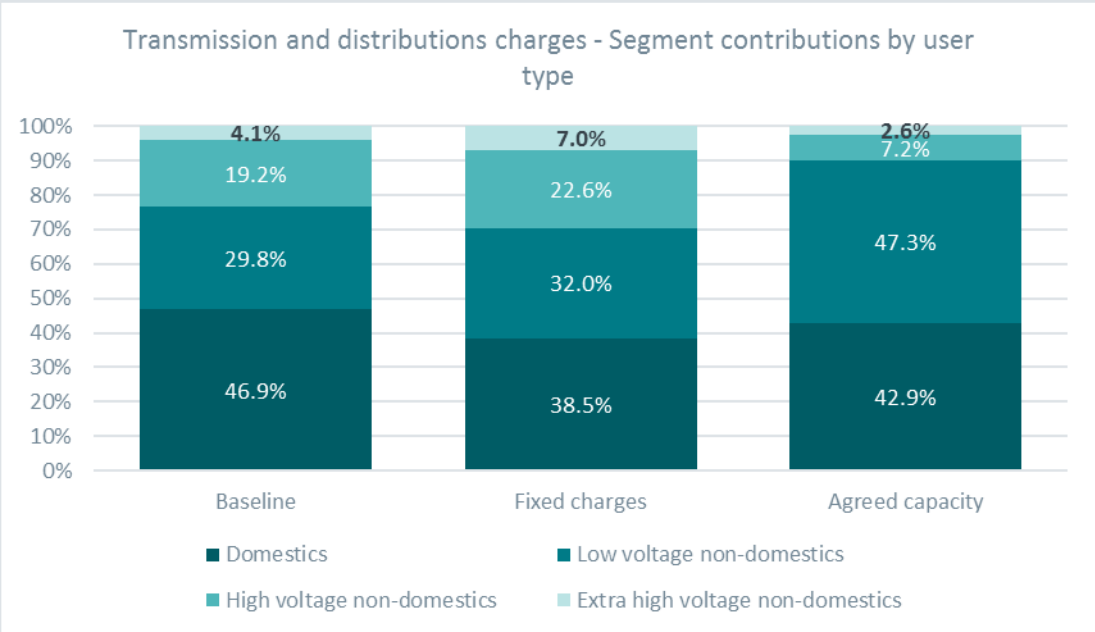
Distributional Impacts of the Leading Options

4.33. The following analysis sets out the static distribution from our proposed reforms and does not include long term savings.

4.34. Fixed Charges (set by segment volumes) lead to a moderate reduction in the overall charges paid by domestic households. A single fixed charge is payable by most domestic users and a different charge for economy 7 users, as these are treated differently in the industry arrangements. There will be reductions in charges for high consuming users as a result of this redistribution of charges because they currently contribute more to residual charges under current volumetric charging. The opposite is true for low consuming users who currently contribute less to residual charges. As all consumers are reliant on the same networks we think it is fair that all users contribute towards the long term future of the system on which they rely.

4.35. Figure 5 shows for the changes to the shares of the overall charges paid by users at different voltage levels, with the low voltage level separated into domestic and non-domestic. The extra high voltage and Transmission voltage levels are also grouped in this chart. Under Fixed Charges, the domestic segment contribution to residual charges reduces, while the other segments see moderate increases in residual charges. This increase comes because of a change in the way charges are allocated, as large user residual charges for the transmission network are changed from a peak capacity basis to a volume-based fixed charge basis. Contributions from higher voltage levels are still markedly lower than under gross volumetric charges because fixed charges are set by net volumes.

Figure 5 Distributional impacts of the leading options comparative to current arrangements[31]



4.36. Figure 5 also shows the shift in charges between segments under our Agreed Capacity Charging option. This option uses assumptions of capacity for domestic users and those non-domestic users without capacity agreements. The capacity assumptions used directly impact the levels of revenue allocated to each segment. Because we assume relatively low amounts of capacity for domestic users, more of the charges is allocated to non-domestic users than in our basic option.

4.37. For the majority of domestic users (75%), we assume around 4kVA capacity. For the highest consuming domestic customers in the top quartile, we assume 6kVA (15%), and 8kVA for higher users such as owners of EVs and heat pumps (c.10% of users) because it is likely they will require a higher capacity for these activities. Under the Agreed Capacity Charging option, contributions from users connected at the higher voltage levels, who will have capacity agreements, rather than deemed capacity, fall significantly.

4.38. Under the Agreed Capacity option, the majority of the residual charges are allocated to non-domestic users on the low voltage parts of the network. Following engagement between our consultants and the DNOs, we established a deemed capacity value for all low voltage non-domestic users without capacity agreements of 55kVA, the same as in our basic option.[32] This assumption, and the very large number of low voltage non-domestic users on the system, means they are assumed to hold a significant proportion of the capacity on the system. As a result, low voltage non-domestic users contribute nearly half of all residual charges.

[31] Please note that EDCM is not included.
[32] An additional sensitivity was carried out where lower deemed levels were assumed for small and medium businesses as well as domestic users, assigning 15kVA and 30kVA respectively to the LLFCs containing lower and higher consuming SMEs. This reduction in LV non-domestic capacity leads to domestic users paying 57% of residuals, with EHV and Transmission sites contributing over 15%.

4.39. Larger users connected to the high voltage and extra high voltage levels of the distribution networks and those users directly connected to the transmission network see their contributions to residual charges fall under our Agreed Capacity option. This reflects the fact that these users hold relatively small amounts of agreed capacity compared to the other users on the system.

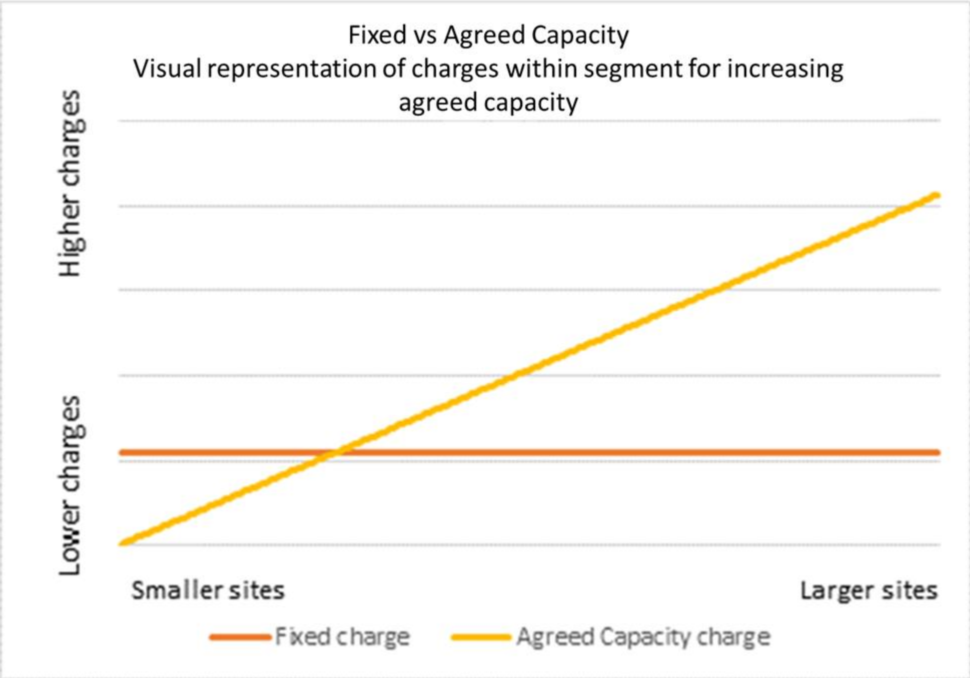
4.40. Where deemed values for low voltage non-domestic consumers are reduced, or where domestic consumer deemed values are increased, domestic users pay a substantially larger proportion of overall revenues. We consider that the requirement to identify and potentially to update appropriate levels of capacity for users with deemed capacity to be a disadvantage of this option when compared against our preferred option of Fixed Charges. While the volumes on the system can be measured or forecasted relatively simply, establishing the appropriate levels of capacity may be more complex.

4.41. We have used a number of deemed bands, set using annual consumption, to provide a range of charges for domestic users. We considered three separate deemed bands to constitute an appropriate number. We would like feedback, as set out in Question 4 on our proposals, and are also interested in views on how the number of deemed bands and their consumption ranges might be reset or updated over time.

4.42. Where Agreed Capacity Charges will vary with the size of the user (through deemed band or agreed capacity) Fixed Charges will not, with the same charge applying to all users in an LLFC group. As extra high voltage and transmission sites covering a significant range of size, this standardisation of charge may lead to increases or decreases in capacity agreed. Our modelling assumes that for Fixed Charges, the same charge would be paid for a given Line Loss Factor Class regardless of the size of the plant, unless additional bands were added (for example to split out smaller and larger users within a band). For Agreed Capacity charges, the charges paid will increase proportionally with the size of the user's connections. For smaller sites, no smaller fixed charge will be payable, while capacity based charges will scale down accordingly. For example, a 2MW extra high voltage site might pay around £25k per annum, while a 200MW site would pay closer to £2.5m per annum.33 A representation of this relationship is shown below.

[33] A full list of unit rates is included in Frontier's Distributional and wider system impacts of residual charges. It should be noted that the extra high voltage sites may include some generation-only sites which we would not be intending to charge residuals to. The removal of these sites may lead to changes in the modelled level of charges.

Figure 6 Fixed Charges compared to Agreed Capacity Charges within segments



4.43. We are seeking feedback on stakeholders' views of fairness and proportionality of these options, and, would welcome feedback on how fairness within segments might be addressed, if it is considered to be necessary, using existing data in a similar way to how we have used LLFCs to determine the segments.

Extra high voltage and Transmission-connected sites

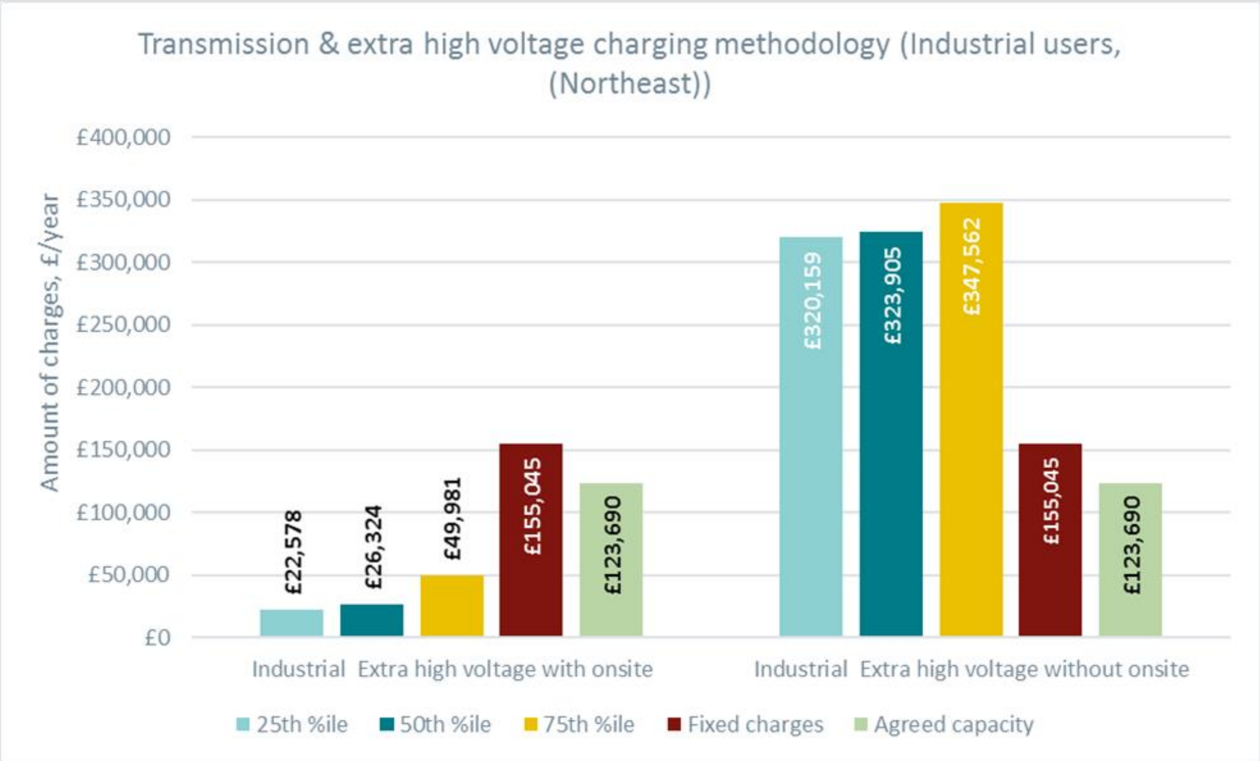
4.44. The degree of change seen by extra high voltage sites is dependent on their current charge. There is significant variation in charges due to location and whether the user manages their exposure to triad charges[34]. For those who do not participate in triad management, both charging options may lead to significant reductions in charges (Figure 7).

4.45. For the transmission-connected user group in our example, charges remain roughly the same where no triad management is in place, but large increases will occur for those who use triad to reduce their exposure. We think this is fair outcome, since taking such action results in lower residual charges but does not bring reductions in system costs. Users paying the same charges reflects the fact that the costs of the existing infrastructure do not change. This is a significant difference from the baseline and one that is more consistent with the TCR's objectives of improving fairness and reduced distortions (in this case competition between customer sites).

[34] The three time periods over which electricity consumption is measured to calculate charges, including residual charges.

4.46. Our example user groups consider extra high voltage sites with 10MW connections consuming c.50GWh per annum and Transmission-connected sites with 20MW connections consuming c.100GWh per annum. The EHV sites will pay £155k per annum under our Fixed Charge option[35]. This is likely to be a reduction in charges where a user is currently not able to avoid triad charges. The Agreed Capacity option leads to a charge of around £124k per annum, again a reduction where users are currently exposed to transmission charges.

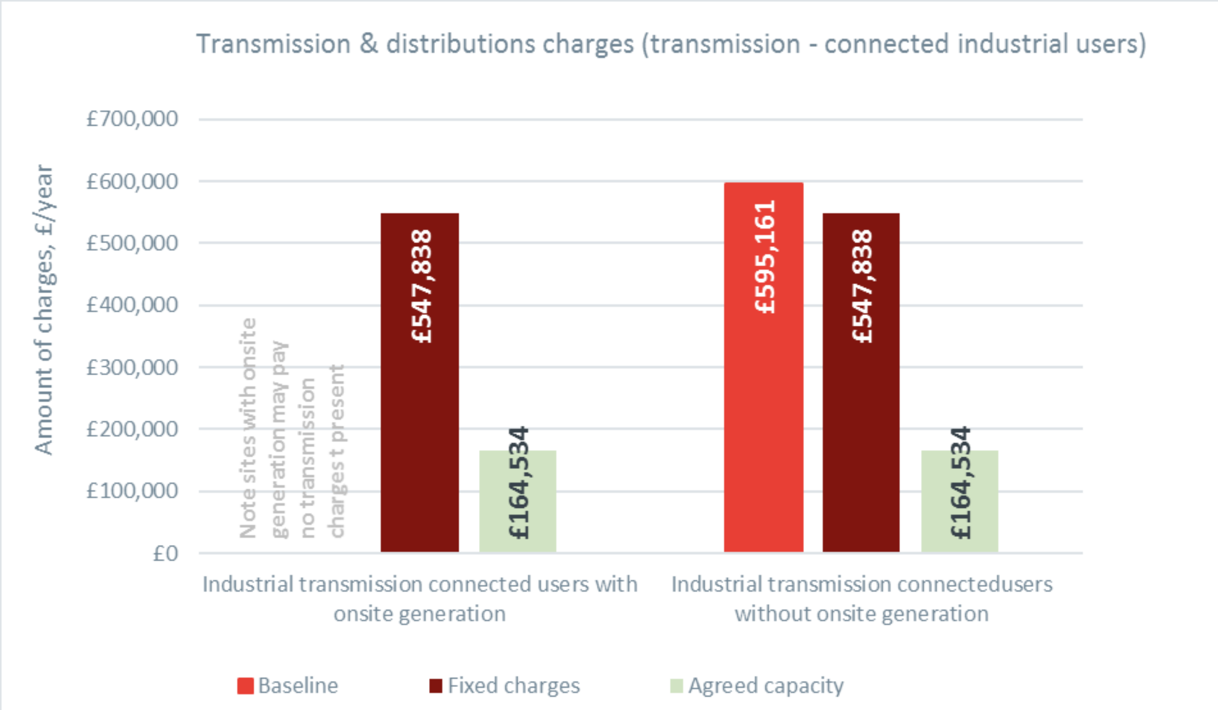
Figure 7 Industrial extra high voltage connected user groups – Transmission (TNUoS) and Extra high voltage distribution charging methodology (EDCM) residual bills for baseline, fixed and agreed capacity options



4.47. For transmission-connected plant (Figure 7), a site with a 20MW connection consuming c.100GWh per annum gross, would receive a £547k Fixed Charge. Under the Agreed Capacity option, this charge would be significantly smaller for a site of 20MW, at £165k per annum. However, the Fixed Charge would remain the same whether the site reduced its capacity to 2MW or expanded it to 200MW. For Agreed Capacity Charges, connections of this size would generate residual charges of c£16.5k and £1.65m respectively. These sites would not be liable for distribution residual charges, as sites pay residual charges only for the voltage levels to which they are connected and those voltage levels above.

[35] All estimates assume that suppliers fully pass residual charges through to consumers.

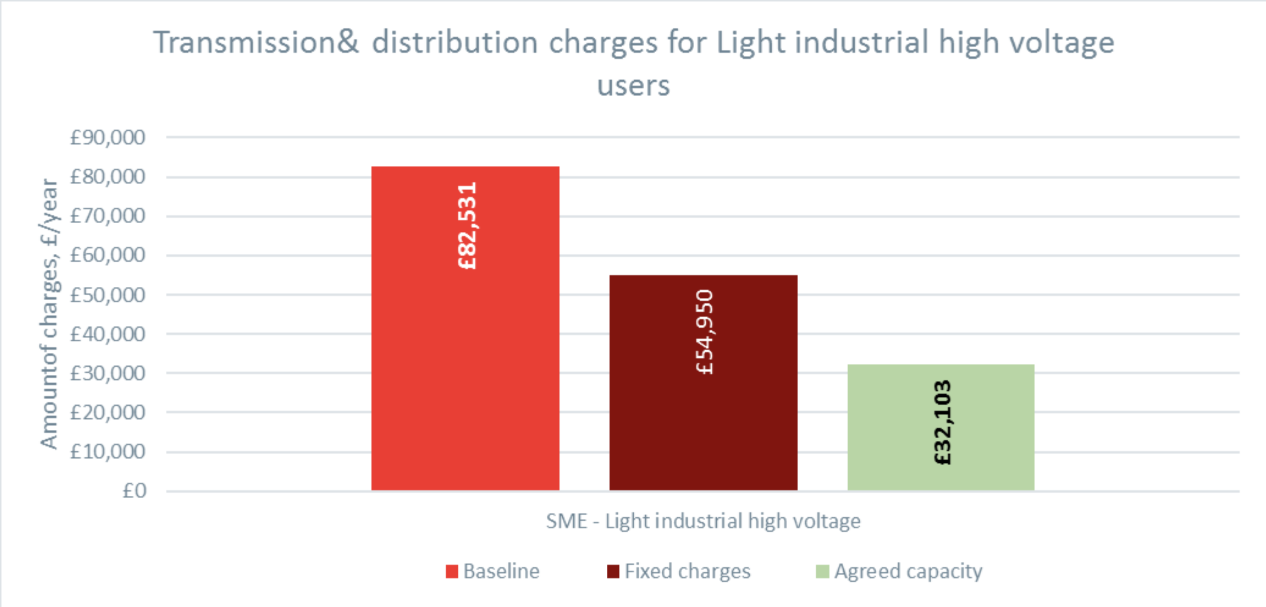
Figure 8 Industrial transmission-connected user group – Transmission (TNUoS) residual bills for baseline, Fixed and Agreed Capacity Charges



Industrial non-domestic users

4.48. Our example of a high voltage user group (Figure 9) demonstrates that larger sites of the type set out in our example pay significantly less than the baseline under both leading options. Importantly, these Fixed Charges would be paid by all users in this Line Loss Factor Class, regardless of individual capacity or volumes, while capacity charges would increase or decrease in line with their Agreed Capacity. Our high voltage user group is based on a 2,000kVa connection, so larger sites would pay more and smaller less. Under our Fixed Charges option, there would be a single fixed charge for high voltage users. We welcome views on whether a single charge is sufficient for this group, and if evidence can be provided to show it is not, how additional charge bands might be produced, using existing data.

Figure 9 Light industrial high voltage (HV) user group – Transmission (TNUoS) & CDCM residual charges for baseline and basic options



Large user responses

4.49. Our work in this area suggests that incentives for large users to disconnect are highly site-specific and explained further in the Large User Report. The extent of electricity use alone does not determine the likelihood of disconnection, but is an important factor among many. Both our leading options have the potential to increase charges for large users who are currently managing exposure to triad charges because of the need to recover costs which do not change with use. However, improvements in the predictability of residual charges due to these reforms may also be welcomed. While an increase in residual charges may increase the likelihood of disconnection, we expect that, for most users, the overall likelihood is low. Where large users who are not currently engaged in activities that would reduce their exposure to residual charges see a reduction in charges after the TCR is implemented, we would expect this to further reduce the likelihood of their disconnection. For the largest users, the Fixed Charges option may reflect a relatively small annual cost in terms of overall expenditure, but they are likely to represent a proportionately very large cost for smaller users. As with other segments, some users will benefit and some will see increased residual charges.

4.50. We are seeking views on whether single fixed charges for each voltage level for these largest users is appropriate, or if further division is needed. We do not currently think that there is a case to increase the number of bands, because this would require more granularity, or detail, than our current proposal for segmenting users (using Line Loss Factor Class and Voltage levels) would allow, and also further segmentation may increase complexity or the ability to avoid charges. If stakeholders disagree, we would welcome evidence as why additional bands would meet our three stated objectives better, and how they would be set using existing industry data to allow prompt change to take place.

Commercial non-domestic users

4.51. The following chart (Figure 10) sets out the impacts on a range of commercial users and SMEs over a range of consumptions.

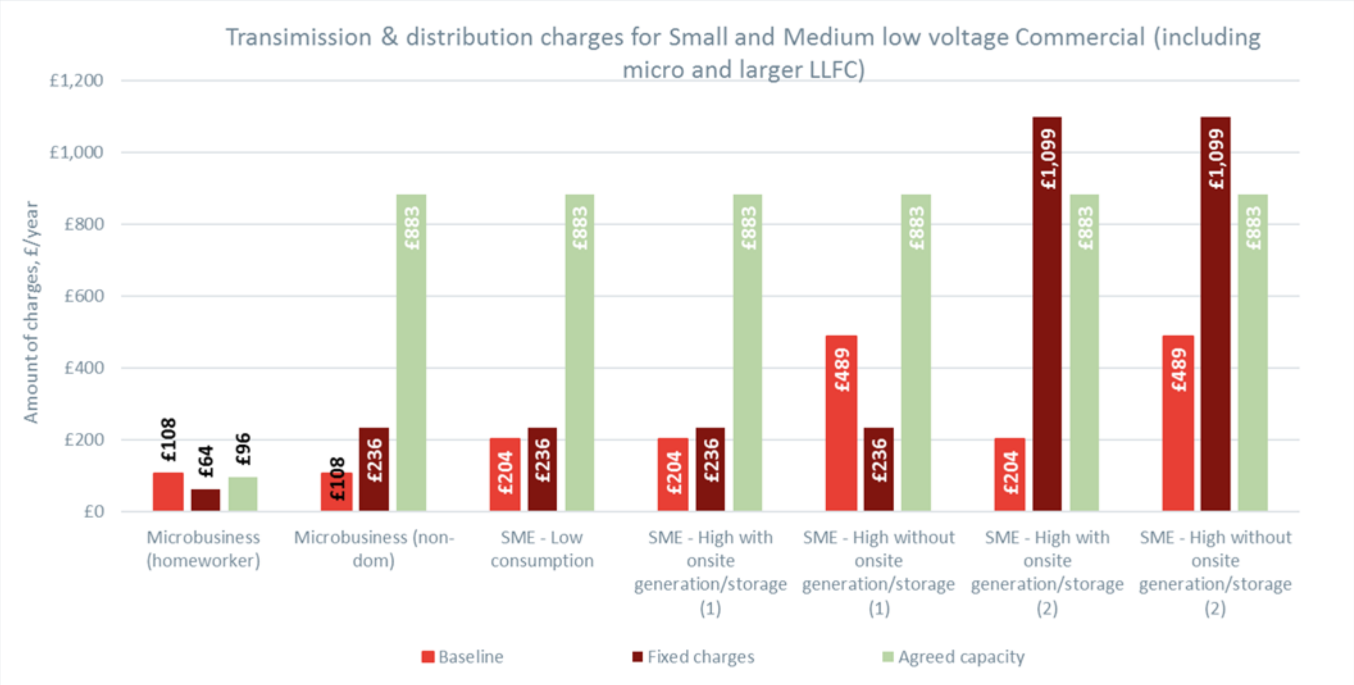
4.52. All SMEs in the same LLFC will receive the same charge under the Fixed Charges option, meaning that larger users will see reductions[36] and some users at the lower consuming end will see moderate increases. Notably, users with on-site generation will pay the same charge as those without, in contrast to the existing arrangements.

4.53. The smallest microbusiness users in non-domestic LLFCs may see some significant increases in charges under the Fixed Charges option, and very significant increases under Agreed Capacity options. This is because these users will move from being charged on a volumetric basis on their own consumption, which may be similar to that of a household, to a Fixed Charge which reflects the average consumption within an SME Line Loss Factor Class, which is much higher. The Agreed Capacity Charge option would also see an increase, as these users would have a deemed capacity set at the non-domestic deemed level, unless other arrangements were made for microbusinesses.

4.54. A large SME site could pay a Fixed Charge of £236 in one LLFC, or £1,099 in another. The different LLFCs are indicated below as (1) or (2). Under an Agreed Capacity Charge option, sites of this type would pay £883, representing significant increases for many. This is due to the recommendations for assumed capacity levels we received from our consultants. Where users have agreed capacities, these charges would differ. We would expect these to be higher as such sites would typically hold higher levels of capacity than the deemed values used here. We are interested in views on whether and how particular users, such as microbusinesses, might be treated differently. Figure 10 demonstrates how the our proposed options will apply to a range of non-domestic users, including users with and without on-site generation.

[36] There are a range of LLFCs shown here. Microbusiness (homeworker) is based on Dom Hi (4600kwh) and assumes a domestic LLFC eg Profile Class 1&2. Microbusiness (non-dom) uses the same baseline, but assumes in non-domestic LLFC "Small Non Domestic Unrestricted" eg is in Profile Class 3&4. SME - Lo corresponds to the CLNR median SME user and is in LLFC "Small Non Domestic Unrestricted". SME - Hi (1) corresponds to the CLNR SME upper quartiles, and sits within the LLFC " Small Non Domestic Unrestricted". The SME - Hi (2) also corresponds to the CLNR SME upper but sits in LLFC "LV Network Non-Domestic Non-CT". A user close to mean consumption would see a similar fixed charge. More information on deemed levels used can be seen in the segment section above and in Frontier's report.

Figure 10 Small medium low voltage (LV) commercial user groups – Transmission & Distribution residual charges for baseline and basic options



Domestic and Vulnerable consumers

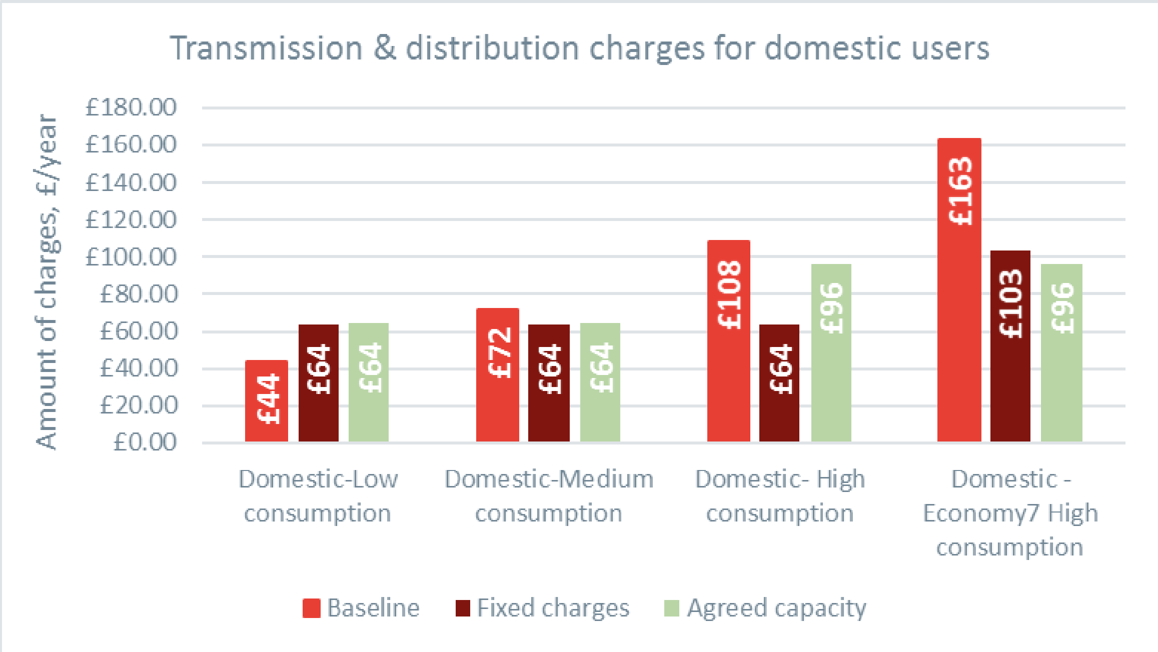
4.55. The following chart (Figure 11) provides an example of the impact of change on a typical DNO (Northeast)[37] on domestic users. Both of our leading options lead to annual reductions in residual charges of around £8 for the median user. Higher consuming users see reductions in their charges, and low consuming users will see increases. Users with Economy 7 meters using 7,100 kWh, reflective of the upper quartile of these users, see large reductions in their charges, paying £60 less under the Fixed Charge option and £67 less under our Agreed Capacity Charges option. Both options lead to increases in charges for low users of around £20 per year.

4.56. We are particularly interested in views on whether the Agreed Capacity bandings set for domestic users are appropriate, including whether the use of volumetric consumption to generate domestic deemed capacity bands is distortive. We are also interested in views on whether separate fixed charges for single-rate and Economy 7 users (which relates to their separate Line Loss Factor Classes and segment consumptions) is appropriate. Alternatively, grouping domestic users, which would increase charges for single rate users, may be possible, or a different banding method may be possible. We would expect any proposals to be achievable within the constraints of available or easily obtainable data. We are also interested in views on whether separate charges for single-rate and Economy 7 users are likely to send distortive incentives to choose one metering arrangement over the other, and on whether there are likely to be particular impacts on less-common metering

[37] Full DNO analysis can be found in the Frontier report. The impacts on users varies across DNOs as the revenue required to be collected by each DNO from residual charges and the number of customers of each type varies significantly across GB.

arrangements like related Meter Point Administration Numbers (MPANs), where more than one meter is be present on a single site.

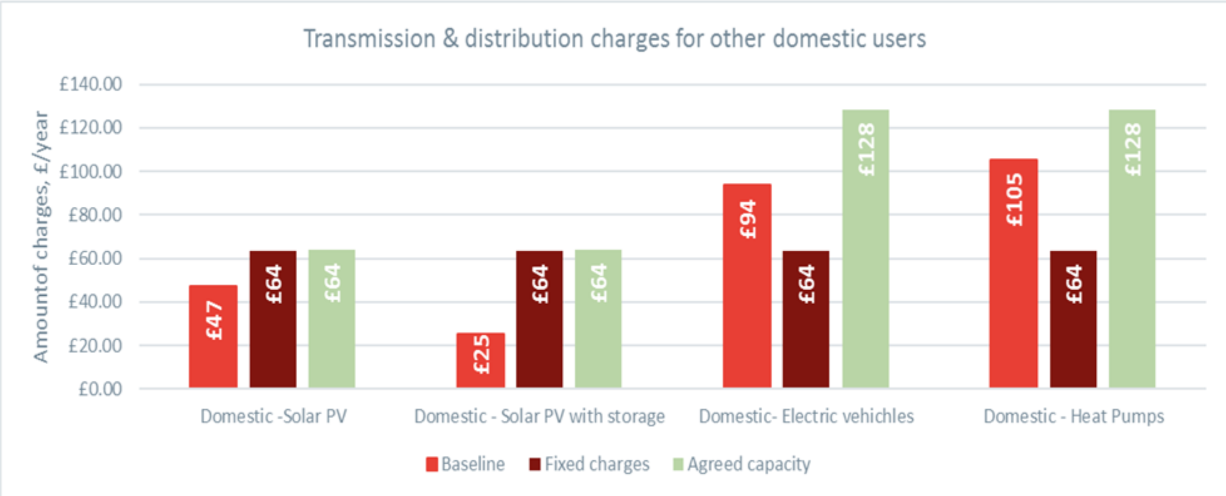
Figure 11 Impacts of charges on example domestic users



4.57. The chart below (Figure 12) sets out the impact of the leading options on users of low-carbon technologies. Here the users are all single rate users, rather than Economy 7 users, meaning the same Fixed Charge is paid. Their consumption before use of the low-carbon technologies is added is equal to that of a medium domestic user. Solar PV and Solar PV and battery users will see increased charges in all cases. This is because, currently, the use of these technologies substantially decreases the contributions users make to residual charges, for those with the lowest consumptions.

4.58. This illustrates the impact of certain technologies of residual contributions. The benefit of lower use of the networks is already reflected in reductions in the cost-reflective element of charges. The Fixed Charges option will lead to reductions in residual charges for those using more electricity such as electric vehicle and heat pump users, as all single rate users have the same Fixed Charge based on their Line Loss Factor Class. Under our Agreed Capacity option, the different domestic deemed capacity bands recognise a correlation between higher volumetric consumption and increased capacity requirements, and also allocate more capacity to higher users such as those with electric vehicles and heat pumps. This means the Agreed Capacity option would increase charges for electric vehicles and heat pump users.

Figure 12 Impacts of the leading options on low-carbon technology users



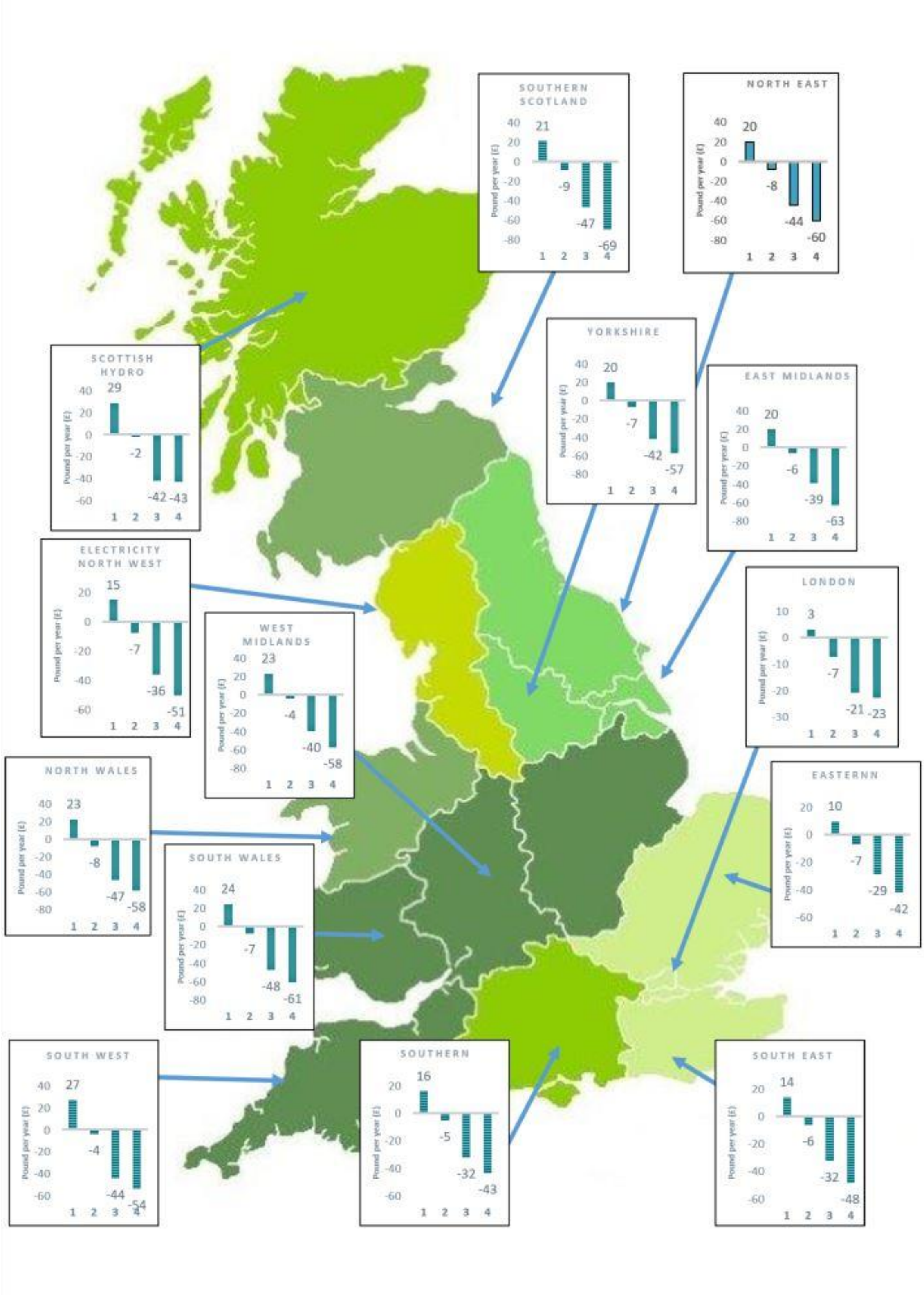
4.59. These choices are made to provide greater differentiation between larger and smaller users and serve to reduce the impact on low users that would otherwise be seen under the Agreed Capacity option. We understand that heat pumps are increasingly being considered by rural users as an alternative to other forms of off-gas-grid heating, and that social housing providers are also considering heat pumps and solar panels for their properties. There may therefore be vulnerability implications for any increase in charges for users of these technologies. We also expect Electric Vehicle uptake to increase, and we therefore assume for the purpose of this assessment that differences for those with electric vehicles would affect vulnerable users equally. Network capacity and electric vehicles is one of the issues being addressed in our Electricity Network Access Project.

4.60. Residual charges are different across the regions of GB. The charts below set out the regional impacts of the proposed changes to different consumer groups in the different DNO areas. These set out the day one static distribution only, and do not include the long term benefits of reform.

4.61. There are locational differences in charging which account for the distances between generators and consumers. If there is less supply than demand, then forward-looking charges may cover more than the allowed revenue (because of locational charging impacts) and as a result total residual charges may be negative. As a result, the impacts of locational difference can be seen on the charts, and is why impacts in London are smaller than in Scotland.

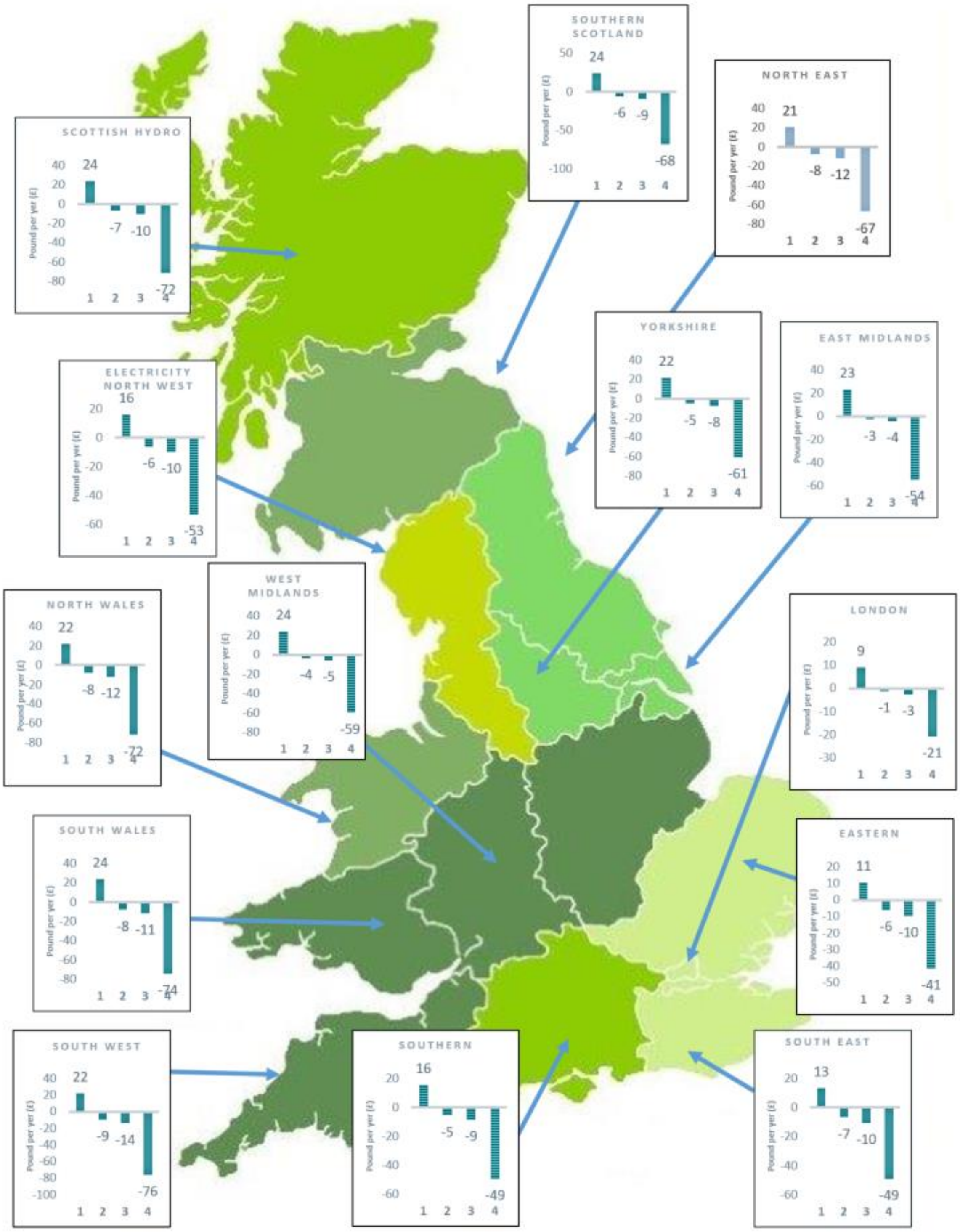
Regional impacts

Figure 13 Regional distribution impacts - Fixed Charges Option



Group	User group
1	Domestic - Low consumption
2	Domestic - Medium consumption
3	Domestic - High consumption
4	Domestic - Economy 7 high

Figure 14 Regional distribution impacts – ex-ante capacity deemed capacity option



Group	User group
1	Domestic - Low consumption
2	Domestic - Medium consumption
3	Domestic - High consumption
4	Domestic - Economy 7 high

Vulnerable Users

4.63. Our assessments have indicated that vulnerable consumers are present in most domestic consumption groups, and that there are a range of consumption levels in all demographics. The key drivers that impact domestic charging changes as a result of TCR are the user's volumetric consumption and LLFC, as these determine baseline charges and set the deemed bands for most users under Agreed Capacity and help set the fixed charging levels for the Fixed Charges option.

4.64. We have therefore been able to estimate some potential impacts on vulnerable consumers and those with consumption close to a typical and low income fuel poor consumers using a number of datasets including demographic data.

Vulnerable users - Fuel Poor Users

4.65. According to 2016 Fuel Poverty data from the BEIS July 2018 National Energy Efficiency Data-Framework (NEED) publication[38], the median consumption of a user in the 20% most Fuel Poor households is 3,100 kWh per annum. This is exactly the same consumption as our medium domestic user. This means both of our leading options produce charge reductions for the median Fuel Poor user of around £8. For the median user in the 20% most Fuel Poor households in the largest homes (there is around a £73 reduction in charges).[39] For a typical fuel-poor user with a low household income of less than £15k per annum, our Fixed option leads to bill increases of around £5 a year.

4.66. In all cases, there is likely to be a significant range of users within any demographic. Relatively low consuming users will experience residual charge increases, and high consuming users are likely to experience reductions. Figure 15 sets out the existing charge levels for the typical (median) lowest-income users in the most deprived areas (Green) and the typical (median) lowest-income most fuel-poor users (Turquoise), and the most fuel-poor in the largest homes (Teal) using the statistics from BEIS 2018 NEED data. This suggests that in the Northeast distribution network area, users consuming more than 2800kWh are likely to pay the same or less under our preferred Fixed Charge option. This suggests that many vulnerable users would benefit from the changes we are proposing, although there is likely to be increases in annual bills for those who have the lowest levels of electricity use.

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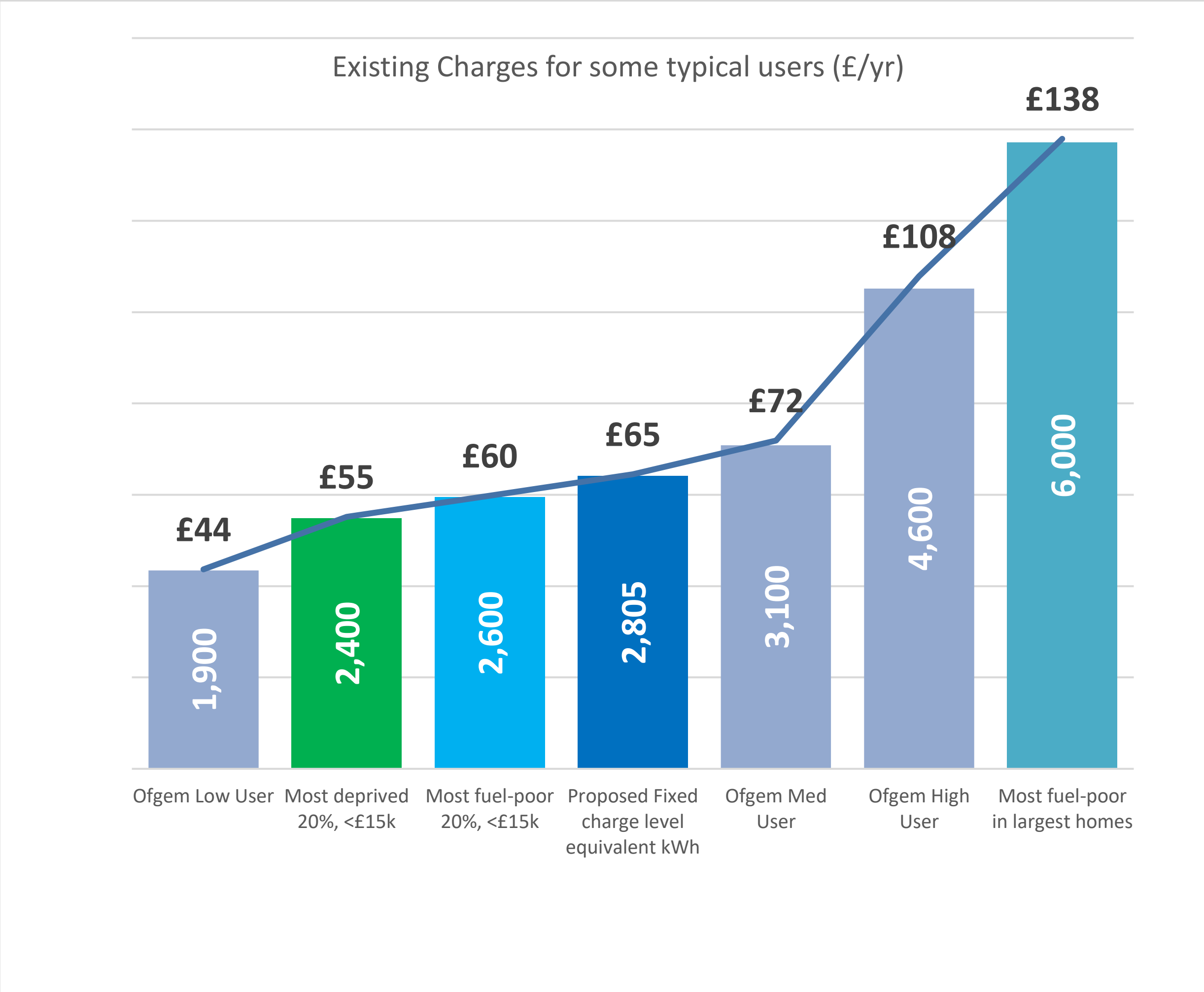
[38] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/720047/National_Energy_Efficienct_Data-Framework__NEED__Summary_2018.pdf

[39] The median consumption for these users, whose homes are larger than 200m^2, is c.6000kWh per annum.

Figure 15 Existing charges for some typical users



Other vulnerable users

4.67. Vulnerability has a wide range of definitions, and we expect vulnerable consumers are present in most domestic consumption groups. There are some existing protections in place for vulnerable consumers currently, such as the Warm Home Discount Scheme, and more the price cap. We have a statutory duty to consider persons who have a disability or are chronically sick, have a low income, are of pensionable age or reside in rural areas. We think that our potential mitigation for low consuming domestic consumers who may face increases in residual charges will help the vulnerable in this group. Other user groups, including the vulnerable consumers within them, are likely to see reductions in residual charges.

4.68. The key information we have that allows us to understand the impact of our leading options on a user's charges is their consumption. However, in many cases we do not have demographic data that would allow us to identify which users are vulnerable. We have therefore sought to understand whether a user's consumption was indicative of vulnerability, or whether certain types of vulnerability might lead to particular consumption patterns. To understand these issues better, we looked at information gathered from a number of electricity usage trials.

4.69. Our consultants, Frontier, have used data from a network innovation project called Customer Led Network Revolution (CLNR) to produce our example user groups. This project gathered data on the electricity consumption of a large number of users across a range of user types. The CLNR project report notes that electricity consumption patterns vary across demographics but it suggested a relatively consistent average demand profile across the different demographic groups, with much higher variability within groups than between them.[40]

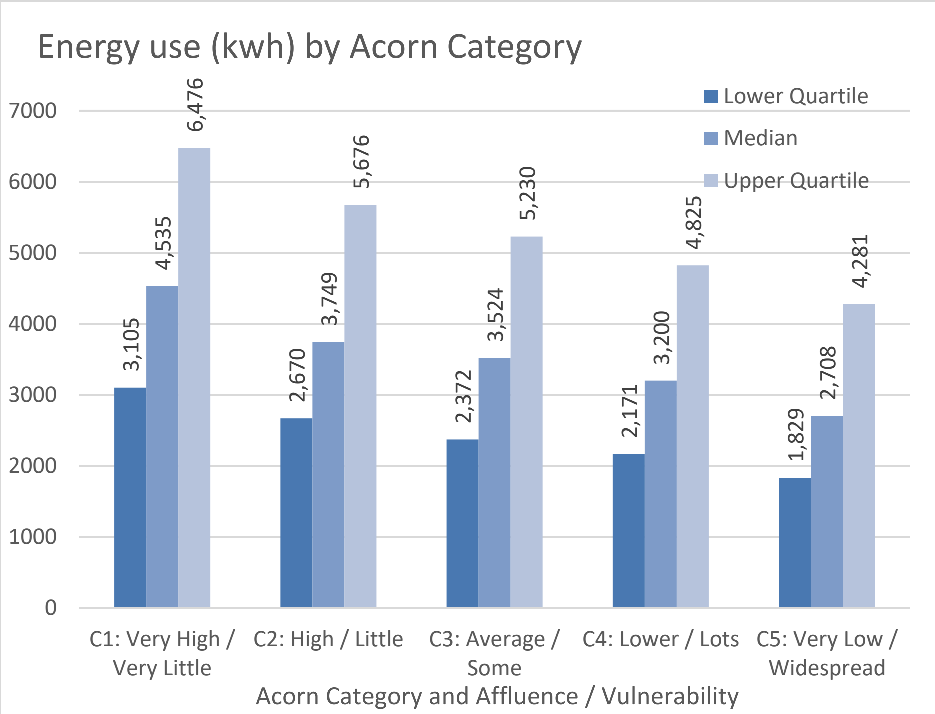
4.70. The CLNR report also asserts that a link between customer consumption and demographics is primarily driven by income. However, it stresses that this is not a strong driver, with most averaging 3,500 kWh, with the exception of high-income groups (4,100 kWh) and rural off-gas users (5,300 kWh). The low income group used around 3,000 kWh. As these figures differ from the TDCV figures used to create our users, there may not be a direct read-across, but this does suggest that, while there is variation based on income, it is not great, and there is significant variation within groups.[41]

4.71. To expand on this, we looked at the range of users within two usage trials, the Energy Demand Research Project (EDRP) trials[42], and the smaller LCL (Low Carbon London) trial[43]. These trials include consumption data for a range of users along with demographic information, in the form of CACI's Acorn classifications. These classifications split a large number of types of households and include five high-level categories, which loosely relate to affluence. Combined with the details of the types, we can use these categories - cautiously - as a proxy of vulnerability[44]. Our work here finds a general link between energy use and income.

4.72. The chart below (Figure 16) shows our estimates of the range of consumptions present in the categories set out in the data from the EDRP trial[45] from the most affluent, to the least affluent[46]. As the chart below shows, there is a very significant range of consumption levels within all groups.

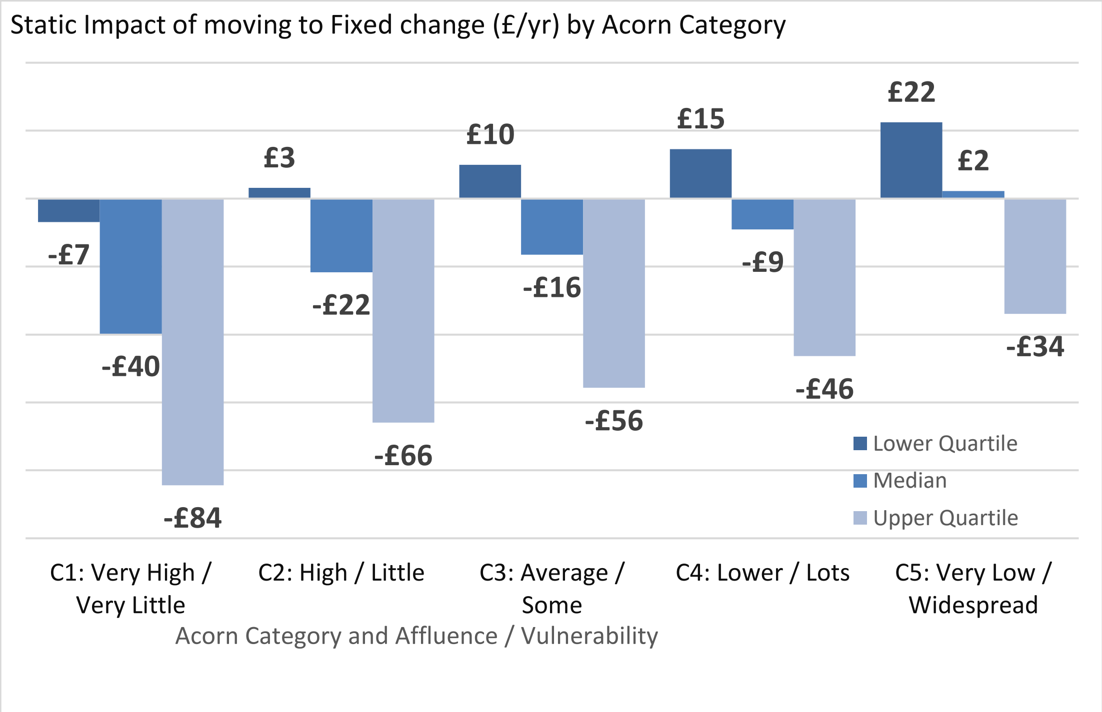
[40] The usage trial from which Frontier have created user groups
[41] Typical domestic consumption values (TDCV) are industry standard values for the annual electricity usage of a typical domestic consumer.
[42] Energy Demand Research Project (EDRP) trial includes nationwide data from 2007-2010. It should be noted that this data is therefore quite old.
[43] Low Carbon London (LCL) trial was London-only (so not nationally representative). It ran to late-2014 and so includes more recent data than EDRP.
[44] Acorn categories are a high-level consumer classification that groups UK population segments by their demographic data, social factors, population and consumer behaviour. They are not designed to shown vulnerability so these findings are used cautiously.
[45] Very similar results were seen for the LCL trial.
[46] We have taken the broad view, based on descriptions of the types of users contained within the categories that category 5 is the category most likely to have vulnerability, with category 1 the least, although there will be nuances.

Figure 16 Range of energy use by Acorn category – EDRP data



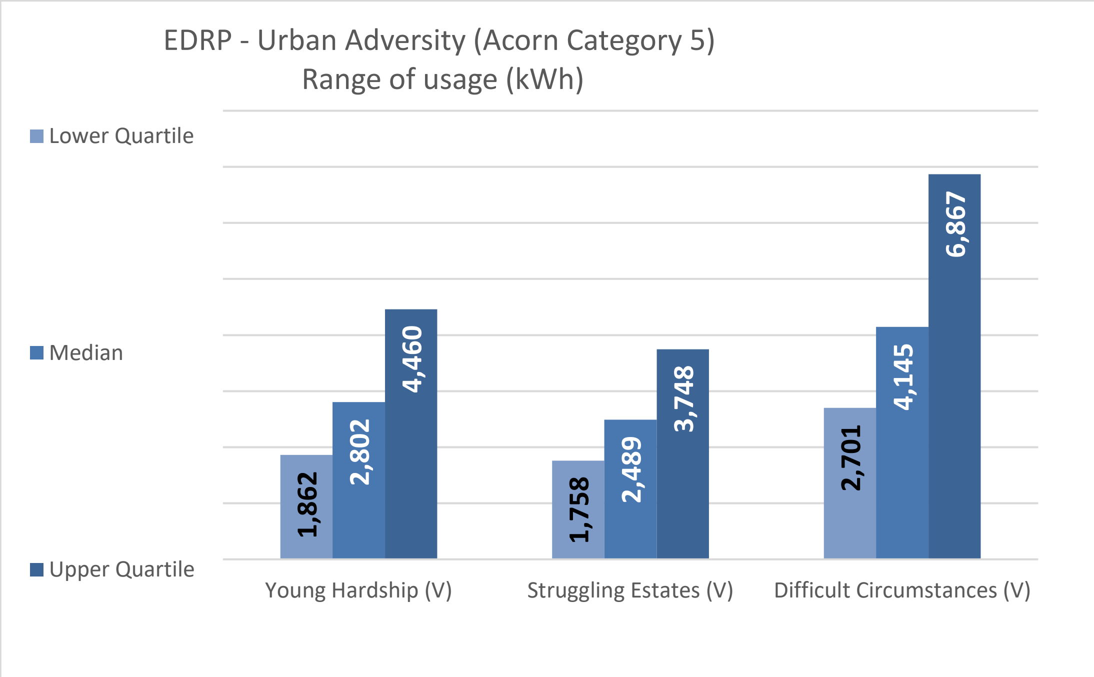
4.73. The chart below (Figure 17), also based on EDRP data, shows an estimate of the change in bill for a user paying a single-rate Fixed charge for each category, based on the range of consumption levels shown in the chart above. The median electricity user in the 'C5' category, where we would expect vulnerability to be most widespread, would see a £2/year increase in their bill. There are a range of consumptions within the C5 category, with consumers who use the most electricity seeing a £34 decrease and those who use the least in the category a £22 increase. We would welcome feedback on how to better quantify the impacts on vulnerable users.

Figure 17 Static impact of moving to fixed charge (£/yr.) by Acorn Category



4.74. Within this category, we can look at the groups, which are the mid-level granularities of users (Figure 18). These figures show very significant variation in consumption, even within relatively well defined user groups, with the upper quartile consumptions here similar to those in more affluent groups. We must stress that data in this area are scarce, and many groups have a very small sample size. Ultimately it may be difficult to differentiate between low consumption that is related to vulnerability, such as low income, and that which is not, such as that reduced by smaller or more modern housing or the use of solar panels, for example. Low users are not necessarily vulnerable and may also include those with second homes.

Figure 18 User consumption ranges - EDRP - Urban Adversity (Acorn Category 5)



4.75. We also considered other means to mitigate impacts on vulnerable users:

a) an additional segment for very low domestic users;

b) volumetric charges for very low domestic users;

c) a hybrid charge including a variable element;

d) targeted discounts (such as aligning to Warm Home Discount); or

e) ensuring transitional arrangements allow appropriate adjustment time for all consumers and reduce year-on-year changes in charges

4.76. We are minded to consider only transitional arrangements as an appropriate way forward to manage these impacts as these would not create unintended consequences. Transitional arrangements might, for example, reduce year-on-year changes in charges, although this may lead to vulnerable users with higher consumption levels seeing reduced benefits. Other options including volumetric or variable elements retain greater distortions and will be difficult to limit to vulnerable users. We do not currently consider there to be a clear means of using targeted discounts to identify affected vulnerable users.

Issues related to Onsite generation and generation sites with significant demand

4.77. Our current proposal is to levy residual charges on final demand users, and not charge them to generation. For instance, where a demand load co-locates with a generation site or is connected through the use of a private wire, we do not think the demand load should be able to reduce their residual charges that would otherwise be payable.

4.78. We are seeking views on how best to achieve an outcome that provides a level playing field for demand users and avoids distortions where co-locating with generation or storage avoids demand residual charges.

4.79. For co-located or private wire sites with both generation and demand loads, similar issues are currently being considered by Elexon in their consultation on how to align BSC reporting with EMR regulations, specifically in regard to how to determine what is considered 'final demand' when charging Final Consumption Levies.[47] Elexon's consultation sets out a possible enduring solution on how to determine, and report, the imports used by generation and demand at co-located sites. The solution could also be used to separate out the import at these sites for the purpose of residual charging.

4.80. We consider that the approach currently used by the Low Carbon Contracts Company (LCCC) when estimating charges to a CfD[48] generator may be a sensible approach in this context. The approach currently taken by LCCC when considering which consumption to net off the output of a CFD Generator for charging purposes is to not charge licensed generators for imports to:

a) their generating units; and

b) any auxiliary equipment required to operate the generating units for a sustained period of time safely and efficiently at the maximum capacity possible and without causing damage to it.

4.81. Again, the work being carried out by Elexon and the LCCC, on how to charge Final Consumption Levies, will help to determine what might be considered as 'intermediate' demand in this context and may help develop enduring arrangements for demand residual charging of storage.

Issues related to Independent Distribution Network Operators (IDNOs)

4.82. Finally, we are also seeking views on how these charges may affect IDNO customers, to ensure that such customers receive appropriate protections. We consider that the approach and methodology will be the same, but are seeking views on where this might not be the case.

4.83. IDNO revenues are governed by a Relative Price Control (RPC) which is described in Amended Standard Condition BA2 of their licence. RPC requires that DUoS charges for domestic customers connected to an IDNO network do not exceed the equivalent charges for the DNO within whose distribution area the IDNO is operating ('the host DNO').

4.84. In practice, IDNOs achieve this by simply mirroring the host DNO's DUoS charges. Some DNOs extend this to all customer types while others take a different approach (eg, in the case of generation customers). IDNOs are not required to follow the CDCM but do need to submit a charging methodology to the Authority for approval that clearly sets how their charges will be determined. IDNO charging methodologies must

[47] https://www.elexon.co.uk/consultation/consultation-align-bsc-reporting-emr-regulations/
[48] Contracts for difference

meet a series of relevant objectives which are described within the electricity distribution licence.

4.85. IDNOs are themselves charged DUoS by the DNO. A discount is applied to the DNO's all-the-way tariff to determine the 'LDNO tariff'. This discount represents the saving to the DNO of the IDNO providing the 'final mile'. The IDNO margin is therefore determined by the difference between the LDNO tariff, and the tariff charged by the IDNO to its end user.

4.86. If a DNO changes it DUoS charges, this will be reflected in the LDNO tariff. IDNOs will change their end user tariffs to remain aligned to the host DNO's all-the-way charge. Any change to the calculation of the discount percentage will also impact the IDNO's margin.

4.87. IDNOs tend to have a high proportion of domestic customers connected to their networks. Any change which shifts costs to/from this group could have an impact on revenues.

5. Quantifying the benefits of reform

Section summary

This section considers how the reform options we are considering can be quantified. It explains the main assumptions and results from the wider systems modelling and also reports its challenges. It then considers how changes in the wider system caused by changes in the residual charges are likely to affect the capacity and wholesale markets and how this ultimately affects consumer and system costs.

Questions for Consultation related to this section. Please provide evidence to support your answers.

10. Do you agree with the conclusions we have drawn from our assessment of the following?

a) distributional modelling
b) the distributional impacts of the options
c) our wider system modelling
d) how we have interpreted the wider system modelling?

Please be specific which assessment you agree/disagree with.

Quantifying wider change

5.1. In reviewing residual charges and remaining non locational Embedded Benefits, we have primarily used the TCR principles, and made many decisions using principle-based qualitative assessments after consultation to ensure our principles were sound. The GB charging regime should be principles based and predictable with clearly set out rules and objectives. We have also carried out modelling but this was to gain insight into the potential savings to both the system and to consumers that could be achieved under different National Grid FES 2018, if there was full or partial reform of residual charges and changes to remaining Embedded Benefits.

5.2. To quantify the impact of changes to residual network charging, we carried out distributional and whole systems analysis. This was to ensure we understood the impacts on different types of consumers, environmental impacts and long term impacts on security of supply, future fuel mix, emissions, and technology. We also explored the potential changes in the wholesale and capacity markets through the model.[49] We

[49] We have undertaken this modelling assuming that that the Capacity Market is in place with the current policy framework laid out in the Capacity Market Regulations (2014 as amended). We will ensure we take into account any developments in the framework ahead of our final decision.

wanted to test the effect of the leading options to determine if these changes produced long term benefits, both for the system as a whole and for consumers. We also used modelling to assess how different implementation years and transitional arrangements would impact the results.

5.3. This quantitative analysis was undertaken to support our principle-based assessment of reform options, and should be taken as indicative of the outcomes which are expected from our reforms[50].

5.4. Before running our whole systems modelling, our consultants carried out analysis on the static changes to residual charges. This involved assessment of the impact of different reform options for representative customers, without considering behavioural response. They then used the static bill analysis to assess what behavioural responses might result from the changes to charges with particular emphasis on implications for investment in Low Carbon Technologies (LCTs) and potential responses by industrial and commercial users.

5.5. The main result from the behavioural analysis is that the anticipated changes to usage from the options that we are considering are relatively small. The outputs from this analysis were used to inform the wider systems analysis. A summary of this is shown in Table 8, reproduced from our consultants' report:

Table 8 Implications of behavioural assessment for system modelling

Behaviour/ technology	Summary of potential impact	System modelling implication
Electric vehicles (EVs) Heat pumps Solar PV Solar PV with storage	Overall, the results suggest a limited behavioural impact for all LCTs as the costs/savings represent a relatively small share of the total lifetime costs for each LCT. This applies even under the 'high' sensitivity for most LCTs.[51] The area of greatest potential impact is likely to relate to solar, though we do not consider the solar residual impact to require modelling relating this to element of distortion. It is highly relevant to our fairness considerations, due to the redistribution these actions cause.	On balance, we suggest that it is not necessary to think about scenarios with alternative assumptions around take up of EVs, heat pumps, solar and storage to those assumed in the National Grid Future Energy Scenarios (FES) scenarios[52] adopted in the system modelling.
On-site generation	Most significant impacts expected for these users due to the loss of their ability to avoid TNUoS and CDCM	We propose to model impacts on dispatch and investment incentives

[50] We have taken a cautious approach to our modelling work employing externally validated assumptions where possible. A full description of the work carried out by our consultants is available in Frontier/LCP Distributional and wider system impacts of residual charges
[51] High sensitivity refers to a faster set of assumptions for the decline in renewable technology costs.
[52] National Grid produce Future Energy Scenarios (FES), which are intended to represent "a range of plausible and credible pathways for the future of energy, from today out to 2050" and form the basis of discussions for Government and other stakeholders on the potential development of the energy system. make informed decisions. More information is available here: http://fes.nationalgrid.com/

	charges. This would apply under gross volumetric, fixed and ex-ante capacity charging options. Potential for effects to be smaller under ex-post charging options.	within the system modelling.
Load disconnection	There is the potential for load disconnection among certain types of users with a relatively low cost of investment in back-up power ie those already with existing CHP/baseload generation.	This could be considered as an offset to any reduction in on-site generation investment and therefore can be considered as a driver of uncertainty around the impact of reduced on-site generation on net demand.[53]
Energy efficiency	There is potential for impacts on energy efficiency investment due to loss of triad.[54] This is because investments will need to be viable without 'earnings' from residual payment avoidance. However, given the varied nature of investments, it is difficult to assess impacts quantitatively.	No change to FES assumptions

Source: Frontier Economics

Wider systems modelling

5.6. Wider system analysis has been carried out to understand the implications of changes to demand residual charges at transmission and distribution level and provides an assessment of whether there are consumer and/or system benefits when compared to the existing arrangements. The focus of the whole systems modelling is to see how changes in the incentives provided to avoid residual charges by managing demand during triad periods changes and how this affects the system under different potential future scenarios. Due to the significance of the impact of reform to transmission residuals in particular, our modelling work closely assessed the impact of moving from the current "triad" arrangements, which provide incentives to reduce demand at particular times to removing all potential benefits from avoidance.

5.7. This analysis provided a quantitative assessment of the impacts of removing the ability to avoid transmission and distribution residuals, broadly mapping to the preferred options. This assessment looked at the likely impact on consumer and system costs, energy market dynamics (including wholesale and Capacity Market), generating technologies and their operation (load factors, investment in technologies and fuel mix) up to 2040.

[53] The potential for disconnection of large users was found to be small, further information can be found in Annex 6 and Frontier/LCP Distributional and wider system impacts of residual charges.
[54] Triad refers to the three peak periods in which a user's consumption is measured for the purposes of calculating transmission demand charges, including residual charges. This is because investments will need to be viable without 'earnings' from residual payment avoidance.

5.8. The impacts on network costs are highly location specific. As such, we have assumed that the overall impact on network costs would be neutral as we do not think it is feasible to quantify the impact on network costs accurately. To model these impacts would introduce significant subjectivity into the modelling. It would require assumptions on the exact location of newly connecting generation, plant closures or disconnected sites into the future, as well as estimates of the network costs relating to specific sites. The results would simply have reflected these assumptions rather than anything more fundamental, and have been very sensitive to the assumptions made. As such, we have not provided estimates for the effect on network costs as part of the system cost analysis. Further details can be found in Frontier's 'Distributional and wider system impacts of residual charges'.

5.9. The modelling we have undertaken used LCP's EnVision model[55]. EnVision is a fully integrated model of the GB power market which models the build out and closure of generation and the various market interactions, using the forecasts set out in National Grid's 2018 FES (FES 2018).

5.10. As with any modelling, particularly modelling of a complex nature looking at multi-year impacts, we are conscious of the need to use caution when drawing conclusions. The uncertain nature of certain assumptions, such as future demand, technological developments and commodity prices, means that, no matter what model is used, the outturn may differ from the forecast.

5.11. Due to the high level of uncertainty, we decided to carry out our analysis using a number of scenarios from National Grid's FES 2018. These scenarios are used by National Grid and the wider industry to consider what different possible visions of the future might look like and the consequences of changes to the system under these different futures. We used the two extremes of the four scenarios which are set out in the FES 2018. The one which predicts the least change from the current position (a), and the one representing most change (b):

a) Steady Progression (SP), representing a world where there is slow move to renewables and generation remains mainly centralised; and

b) Consumer Renewables (CR), where there is a rapid renewable generation uptake and a decentralisation of those assets.

5.12. More detailed information about the consumer and system savings can be found in the Frontier / LCP 'Distributional and wider system impacts of residual charges' report published alongside this document. We also carried out sensitivity analysis based on a lower and higher residual, reflecting uncertainty in the size of the residual over the longer term. The model was run after removing the Transmission Generation Residual. Then we considered changes to the benefits captured by on-site generation, we examined:

[55] This model is an electricity supply model, which allows users to analyse the effect of different policy decisions on the electricity market. It is used by BEIS for policy analysis and has undergone extensive assurance testing. Ofgem reviewed LCP's quality assurance process and agreed the input assumptions, using BEIS/National Grid inputs wherever possible. Further details about the model, its assumptions and the future energy scenarios it uses to reflect uncertainty, are detailed in Frontier's supplementary report.

a) the benefit of removing user's ability to avoid transmission demand residual charges. These charges are payable by demand users.[56] In our modelling, the ability to avoid these charges is removed and replaced by the Avoided GSP Infrastructure Cost (AGIC)[57] which provides a justified reflection of the benefit the use of on-site generation brings to the system, consistent with the treatment of other forms of distributed generation. This reflects the removal of the financial benefit of residual charge avoidance through the use of on-site generation to avoid triad periods; and

b) for those sites connected at HV, the benefit of avoiding the CDCM distribution residual. These charges are currently avoided by using on-site generation to reduce net metered consumption (electricity imported from the electricity networks). This reflects the removal of the financial benefit of paying lower residual charges by reducing volumes of electricity imported from the grid through the use of on-site generation

5.13. We have then applied these changes to two factual scenarios, which we can compare to the "baseline" of the current position (where these benefits remain in place). In the first factual scenario, these changes are applied to all on-site generation technologies (Steady Progression Full reform). In the second factual scenario these changes applied only to peaking plant (gas and diesel reciprocating engines) (Steady Progression Partial reform). The latter is consistent with an option (eg net volumetric charging or some ex-post charging options) where baseload generators continue to be able to avoid residual charges, but peakers are not.

The system modelling for the factual scenarios can be mapped back to the charging options under consideration. The leading options all reduce incentives for on-site thermal generation and solar, and so

[56] The Transmission Demand Residual is a charge that recovers residual charges from demand users. This was historically based on a supplier's net transmission demand for serving all their customers. This arrangement led to the existence of "Embedded Benefits", where the use of generation connected at the distributed level rather to the transmission network would not count towards the level of demand that suppliers would be charged at, and would instead lead to a reduction in the amount of charges they would need to pay. This led to a situation where suppliers had an incentive to contract with distribution connected generators to reduce the level of transmission charges they would have to pay. Suppliers passed on some of these reductions in their charges from the use of distribution connected generation (commonly described as "Embedded Benefits") to the generators concerned as Transmission Demand Residual (TDR) avoidance payments. These payments were not cost-reflective, ie they did not relate to system cost savings, and were simply transfers of money from consumers to generators and suppliers. There are also other payments covering other avoided charges. This additional revenue compared to transmission-connected generation was found to be leading to a number of distortions, and Ofgem approved industry proposals to change these arrangements. The Transmission Demand Residual (TDR) avoidance payments were removed. Embedded generators were awarded with a much smaller cost-reflective payment that reflected the benefit of the distributed, rather than transmission-connected, generation. This was called the Avoided GSP Infrastructure Cost (AGIC) credit More information can be found in the CMP264/5.

[57] See footnote 28

are mostly consistent with the Full Reform scenario where the incentives for on-site generation are removed completely.

5.14. Table 9 below.

Table 9 Descriptions of scenarios considered

Scenarios for wider systems analysis	Description
Baseline scenario	Counterfactual. Based on National Grid's 'Steady Progression' FES scenario
Steady Progression (Full reform)	On-site generation has full triad signal and distribution residual benefit removed from April 2020
Steady Progression (Partial reform)	Peaking on-site generation has triad signal and distribution residual benefit removed from April 2020
Alternative FES scenario: Community Renewables	National Grid's 'Community Renewables' FES scenario used as the baseline scenario.
Alternative FES scenario: Community Renewables (Full Reform)	This is run on the full reform scenario and uses a corresponding 'Community Renewables' as the baseline
Steady Progression High Residual	Size of the residual is increased by 50% from the baseline from 2023 to 2030. This is run on the Steady Progression Full Reform Scenario
Steady Progression Low Residual	Size of the residual is decreased by 50% from the baseline from 2023 to 2030. This is run on the Steady Progression Full Reform Scenario

5.15. Table 9 indicates the differences in system and consumer costs under each of our scenarios.[58] Considering both system and consumer costs helps us understand the implications of any change.[59] Frontier and LCP, our consultants, have indicated that the system savings provide the most robust estimate of benefits from reform. There is a greater deal of uncertainty associated with the consumer benefits estimates as some of the elements of consumer cost, in particular costs associated with the capacity market (CM), are inherently unpredictable. CM clearing prices may vary considerably with only small changes in the required amount of capacity needed, due the "lumpy" nature of investments. By this we mean investments which have high capital costs are only

[58] Consumer Costs represent the costs faced by consumers via their electricity bills. This includes wholesale energy costs, network charges, renewable subsidies, capacity market payments and any other charges passed on by suppliers, such as the triad avoidance payments made to on-site generation
[59] System Costs represent the actual resource cost of running the system. This includes, fuel costs, variable and fixed operational and maintenance costs, capital costs, carbon costs (priced at appraisal value) and the cost to society of any expected energy unserved. Consumer Costs represent the costs faced by consumers via their electricity bills. This includes wholesale energy costs, network charges, renewable subsidies, capacity market payments and any other charges passed on by suppliers, such as the triad avoidance payments made to on-site generation

made infrequently. We also think that caution should be taken around the CM results that generate these consumer cost savings. It is reasonable to assume that the costs arising from the CM could be lower or higher, leading to increased or decreased consumer benefits respectively.

5.16. The modelling indicates that there are consumer and system savings in each and every one of our residual reform scenarios. This is in line with our overall aims of finding a charging solution that provides a fairer, proportionate means of reducing distortions. The modelling demonstrates that, by reducing this distortion, in the longer term the system becomes more efficient, creating consumer savings in the long term. There are also reduced consumer costs in the short term because avoidance of residual charges becomes almost impossible.

Table 10 Wider systems modelling consumer and system savings

Projected net benefits to 2040 (£billion)		
Scenario name	**System cost savings**	**Consumer cost savings**
Steady progression -Full reform	1.01	0.54
Steady progression - Partial reform	0.61	0.14
Steady Progression -High residual	1.04	1.57
Steady Progression - Low residual	0.79	0.52
Community renewables - Full reform	3.22	1.23

5.17. Our leading options will both have the effect of significantly reducing the ability of users to reduce their contributions to residual charges. Users will not be able to benefit from the network unless they contribute to residual charges. Avoidance of residual charges will require complete disconnection or reduction of the user's agreed capacity level. Currently, users can avoid triad periods and the associated residual charges with no reduction in the benefits they then get from being connected to the network. This is likely to lead to longer term consumer benefits because the incentive to invest in inefficient plant to reduce grid demand in triad periods is removed. There is likely to be investment in more efficient plant because it has to be profitable without reducing residual charges.

5.18. The largest consumer benefit is seen when the incentive to manage exposure to residual charges at triad is removed from April 2020 under the Community Renewables scenario. This is due to the higher level of investment in a more renewable, decentralised system which has a reduced fuel and carbon cost associated with it. There are, however, still significant benefits shown in Steady Progression scenario.

5.19. There are system benefits in each scenario. The Community Renewables scenario provides the greatest savings overall. These savings are largely driven by decreased fuel and carbon costs as efficient CCGT plants replace on-site gas reciprocating engines. There is also potential for more on-site generation through community renewables which tends towards having greater decentralisation. This means there are potentially greater savings to be made from removing the incentive to avoid residual charges. There are capital cost savings under all reform scenarios. These are largely driven by reduced investment in on-site gas generation and greater use of more efficient Combined Cycled Gas Turbines (CCGTs) and interconnector imports to meet demand. This whole system analysis also considered security of supply, estimated loss of load expectation (LOLE) and possible impacts on the capacity market (CM) and wholesale price. These are discussed in detail in the Frontier 'Distributional and wider system impacts of residual charges' report.

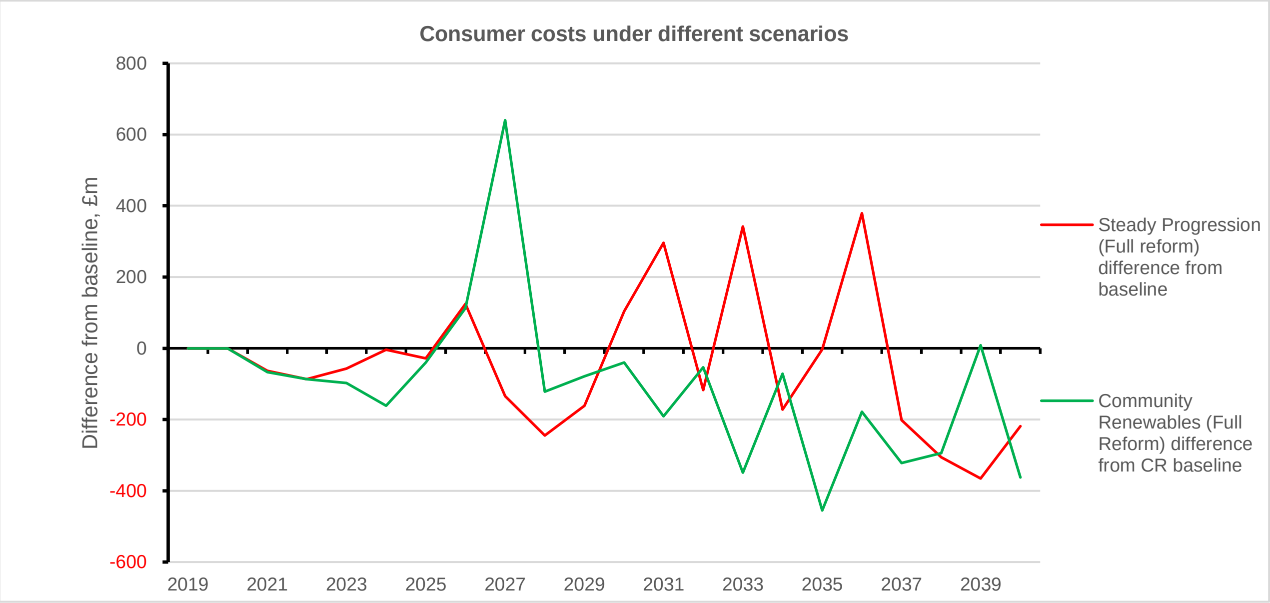
5.20. In regards to our sensitivity analysis on the residual value, our analysis shows that there continues to be significant benefit to reform under scenarios where the overall amount to be recovered from residual charges is smaller or larger than currently forecast. This provides us with reassurance that this reform would bring benefits even if the allowed revenues were to change significantly in RIIO2 or if changes to the charging regime due to the Electricity Network Access Project were to increase or decrease the proportion of charges recovered by forward-looking charges.

5.21. This quantitative assessment supports the longer term case for reforming residual charges, with our preferred option of Fixed Charges resulting in a system benefit of £1 billion to £3.2 billion and consumer benefits of £0.5 billion to £1.2 billion, depending on the evolution of the system and the size of the residual.

Wider systems impact - Consumer Benefits

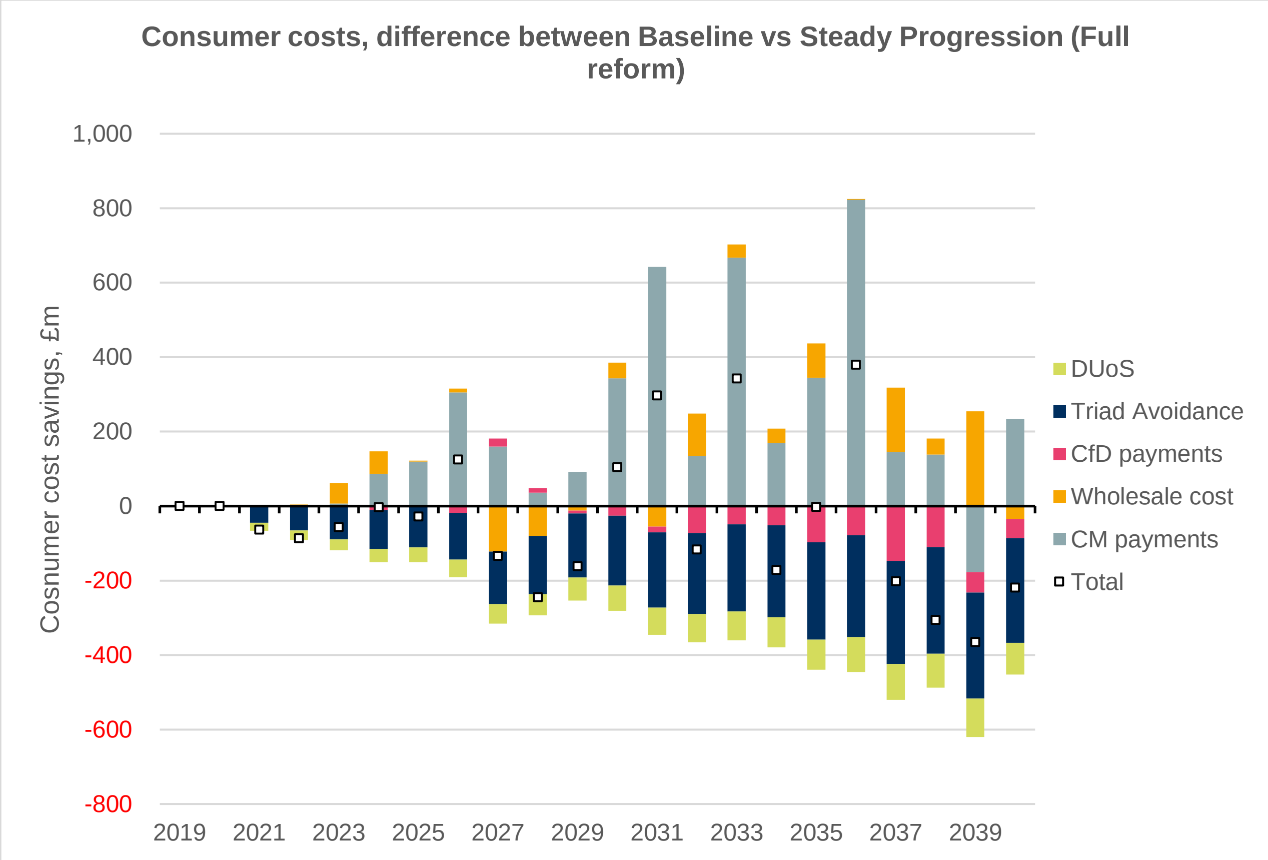
5.22. Figure 19 shows the annual consumer cost savings difference between Steady Progression and Community Renewables after the Full reform scenarios versus their respective baseline scenarios. The results indicate a higher net decrease in consumer costs in the Community Renewables scenario compared to the Steady Progression scenario.

Figure 19 Consumer costs under different scenarios



5.23. Figure 20 shows that consumer cost savings arise from reductions in transmission and distribution charge avoidance the cost of which is ultimately borne by the consumer. Increasing CM payments, due to higher CM clearing prices, represent the largest element of increased cost to the consumer. The increase in wholesale costs is partly offset by a corresponding reduction in CfD payments.

Figure 20 Annual Consumer Cost Savings for Steady Progression(Full reform) versus the baseline

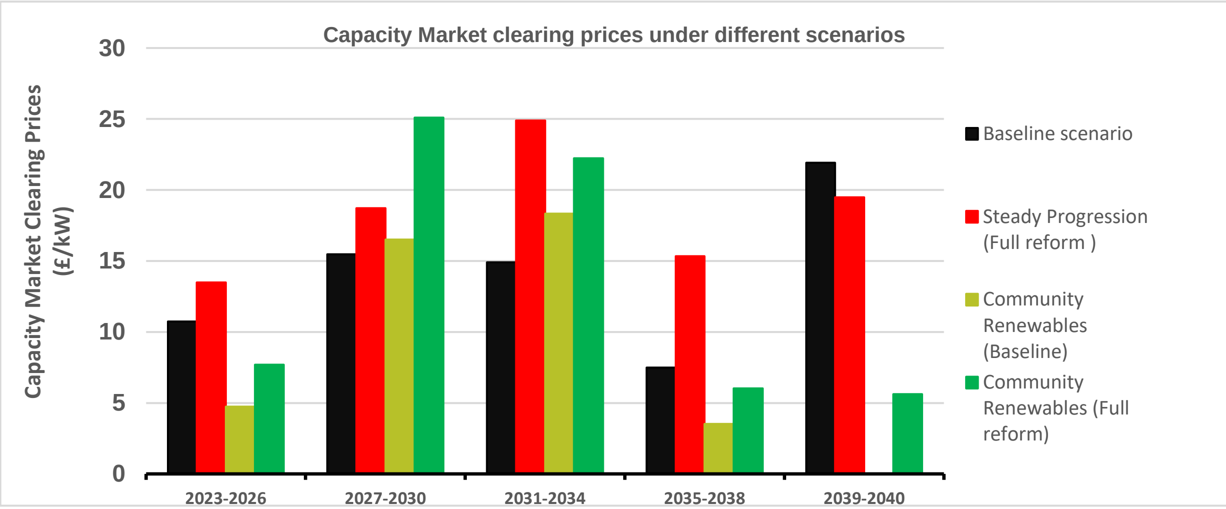


5.24. The majority of consumer cost savings in the scenarios above versus the status quo result from the removal of distribution charging and Triad avoidance.

5.25. Each of the scenarios investigated lead to system cost benefits from reduced fuel usage, carbon emissions costs and some capital expenditure savings due to the transition from on-site gas generation to more efficient CCGT and imports.

5.26. According to Figure 21, in every scenario, removing the triad signal increases the capacity market clearing prices. The observed increase in capacity market clearing prices results from increased on-site generation bids and the building of peaking and CCGT plants.

Figure 21 Capacity market clearing prices



5.27. Overall, the impact on the wholesale price is limited (Figure 22). Removing the triad signal, the incentive to manage exposure to residual charges, in 2020 increases the wholesale electricity price. For the Steady Progression (Full reform) scenario, after 2030, the price is supressed to approximately £43/MWh due to changes in the generation mix, (less efficient on-site reciprocating gas and gas CHP is replaced by new CCGT). The wholesale prices are sensitive to this displacement o on-site technology and overall there are slightly higher wholesale prices under full reform but savings through the inability to avoid paying residual charges. The impact of lower/higher residual charge is negligible.

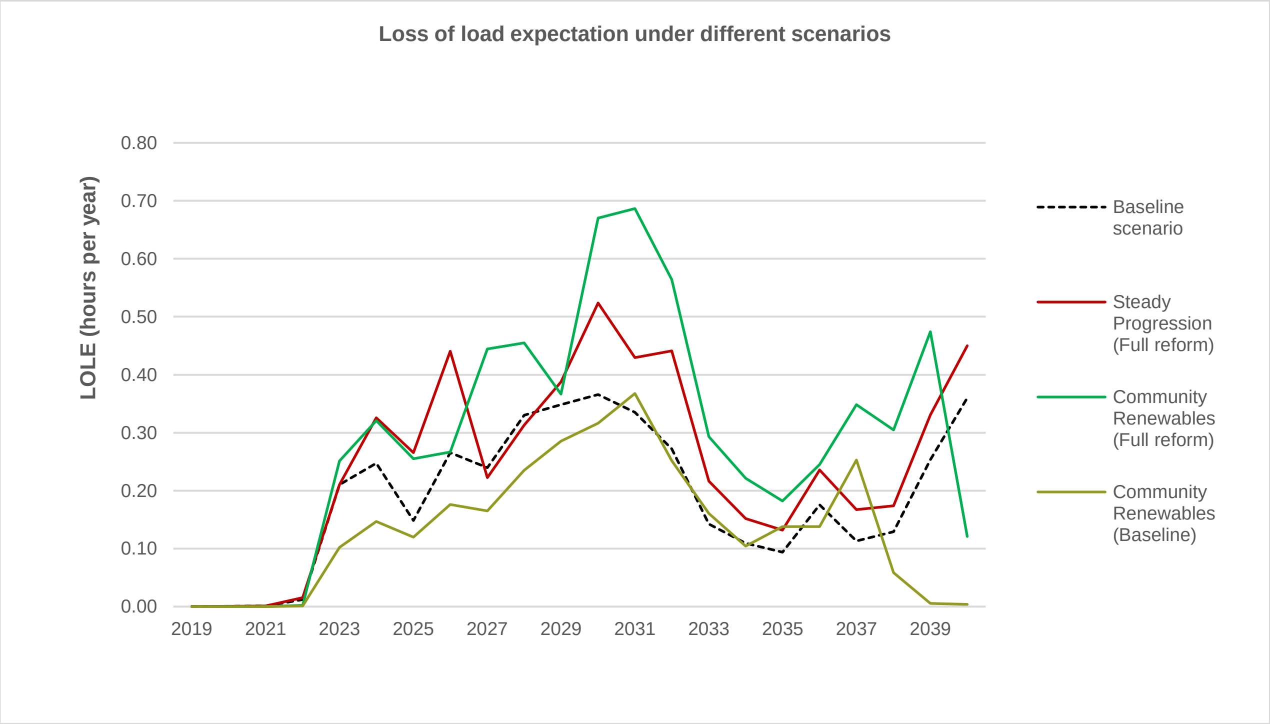
Figure 22 Wholesale price over time

5.28. Investment becomes more difficult in inefficient on-site Gas reciprocating engines, as they require a higher level of support to break even. Initially, both the reciprocating gas engine and the gas CHP make a loss in the wholesale market as revenues are less than the costs. However, the triad benefit allows them to bid at a zero price into the CM as they do not require any additional payment to break even. Removing the triad signal increases the capacity market bids of both the on-site Gas CHP and the reciprocating engine with the latter requiring a significantly higher level of support. Under these assumptions, we expect investment in reciprocating engines to be tougher as significantly fewer reciprocating engines are able to clear.

Security of supply

5.29. The model assessed the impact that changes to triad would be likely to have on security of supply and on the estimated Loss of Load Expectation (LOLE). Overall the system is secure as all scenarios demonstrate low LOLEs, below the Government's reliability standard of 3 hours/year. However, in certain cases there are small increases in LOLE because less capacity is being procured at the higher capacity market clearing prices.

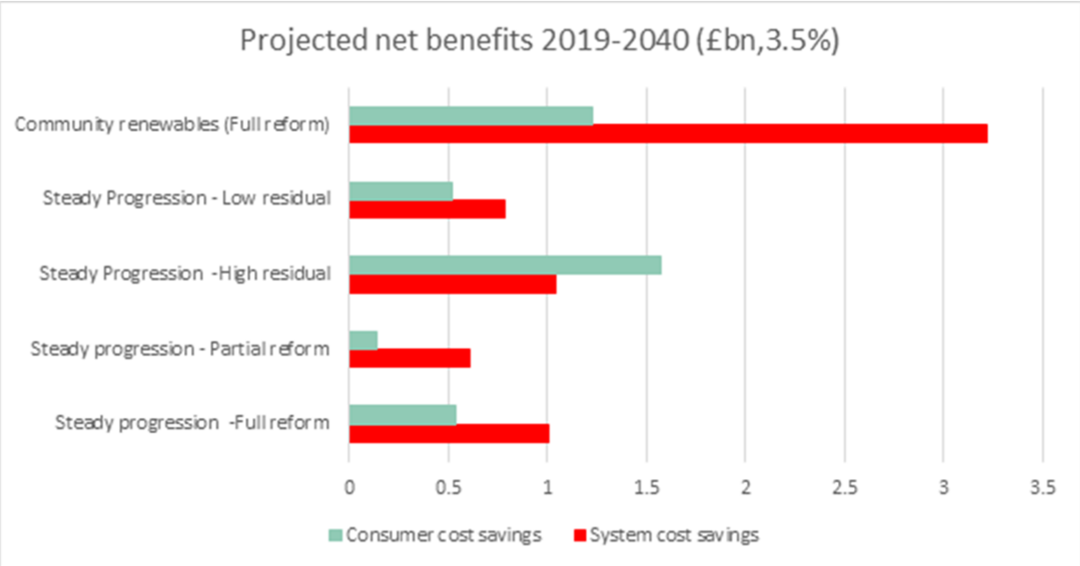
Figure 23 Loss of load expectation (LOLE) under different scenarios



Monetised Outcomes

5.30. The savings to consumers and the system costs indicate a long-term case for reform of residual charges. As described in the previous section, our leading options have a modelled consumer's saving of between £0.5 billion to £1.2 billion, depending on the sensitivity, from triad management costs. There are also system costs savings in the range of £1 billion to £3.2 billion. Both of these are considered for a 21-year period, to 2040. In particular, assumptions which indicate higher levels of renewable and 'local' energy lead to greater consumer benefits of reform. These benefits are represented in below.

Figure 24 Projected net benefits over 21 years



5.31. The main consumer benefits are driven by triad avoidance costs being recovered from users who have been encouraged by the current system to avoid them. However, we recognise that DSR is good for the energy system and this should be reflected in lower forward-looking charges, but the fixed costs of the infrastructure remain the same irrespective of consumption volumes.

5.32. Our modelling suggests little change in the wholesale market although a more efficient system. Currently, some on-site generation bids into the capacity auctions at very low prices, distorting the capacity market. By removing the triad benefit, gas CHP plants will become more competitive and on-site reciprocating engines will become less competitive. This leads to a higher capacity market clearing price. Efficient CCGTs also replace the on-site reciprocating gas generators. The system savings overall because fuel and carbon see cost savings.

5.33. During our assessment of Embedded Benefits last year (part of CMP264/5), we considered the likelihood that changes to system and network charging arrangements would lead to a subsequent increase in the cost of capital across the industry. We have considered the same issues as part of the TCR and we do not consider any increase in cost of capital to be likely, as potential for change in charging arrangements is well established. In addition, we do not consider any increase in the cost of capital to be likely. This is because changes in charges should be factored in, with regulatory reviews being well established. We also do not expect there to be any increase in risk across the industry. Non-discriminatory arrangements, such as those we are proposing, are more conducive to a stable, neutral investment environment where investments are focused on creating value that is aligned with system benefits, and not solely on avoiding residual charges. We consider that any impacts on investment are proportionate and justified by the consumer and system benefits.

Non monetised outcomes

5.34. Under the existing arrangements, some users will pay more than others if they are unable to avoid charges because of uninterruptable process or on-site generation is not feasible. Under our leading options, this is no longer the case. The Fixed Charges option means that similar users will face the same unavoidable charges with disconnection as the only way to avoid paying residual charges. Under Agreed Capacity Charges, the ability to lessen exposure to residual charges is almost entirely decreased in most situations, and only reducing capacity would potentially reduce the residual charge payable. We consider both options to improve fairness and predictability to align well with the TCR principles. The non-monetised benefits of charges that better facilitate the TCR principles are noted below:

a) Reducing distortion – users no longer have incentives to alter their behaviour to avoid residual charges. This may improve predictability;

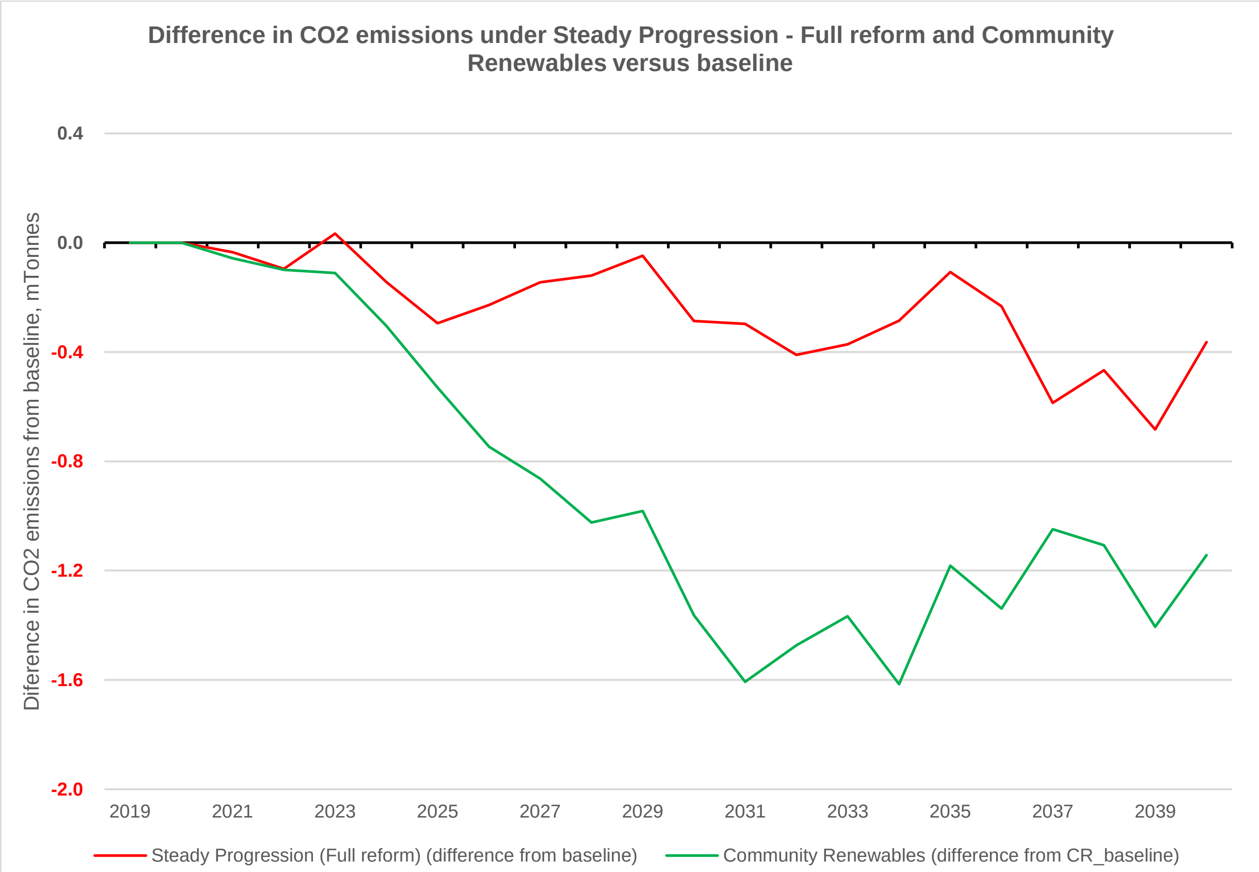
b) Fairness – the requirement that all users contribute to the residual charges makes the system fairer overall, and creates more predictable and transparent charge; and

c) Proportionality and practical considerations – we believe that our leading options may improve the simplicity of pricing for suppliers. This may also remove barriers to entry. More predictable charges should reduce forecasting risks and lead to a reduction in consumer costs. Our leading options are easier to implement, compared to other option which also means a reduced industry cost.

Carbon emissions

5.35. Overall, there is a net decrease in carbon emissions due to this reform as generation from less efficient on-site gas engines are replaced by more efficient CCGT generation and increased interconnection imports. In the figure below, the red line represents the difference in total annual carbon emissions between the Steady Progression baseline and the Steady Progression Full Reform Scenario where charging distortions have been removed. The green line represents the same carbon emission change but between the Community Renewables baseline and the Community Renewables Full Reform Scenario. As shown below, under both scenarios, reform leads to reductions in carbon emissions, which as expected, are greater for the Community Renewables Scenario.

Figure 25 Carbon emission reduction under different scenarios



6. Remaining Embedded Benefits

Section summary

This section discusses the remaining non-locational Embedded Benefits. These are the different charging arrangements for smaller embedded generators versus larger generators. We think there is evidence that the remaining Embedded Benefits create significant distortions to competition and have negative impacts on consumers' interests. As such, we think that reform is required to address these issues. We have used the same TCR principles and approaches to wider system modelling in the assessment of the Embedded Benefits as those used for assessing options for residual reforms. We propose reforms to remove those Embedded Benefits which result from transmission generation residual charges, and those which are due to the way in which balancing services are charged.

Questions for Consultation related to this section. Please provide evidence to support your answers.

11. Do you agree with our proposed approach to the reform of the remaining non-locational Embedded Benefits?

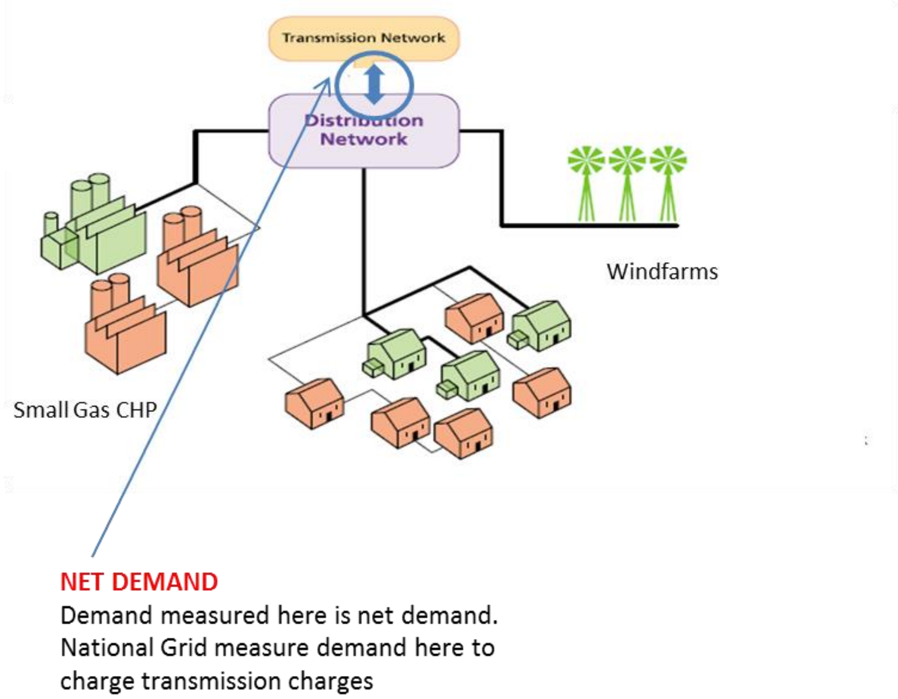
12. Do you agree with our proposal not to address any other remaining Embedded Benefits at this stage? Which of the embedded benefits do you think should be removed as outlined in xx? Please state your reasoning and provide evidence to support your answer.

13. Are there any reasons we have not included that mean that the remaining Embedded Benefits should be maintained?

6.1. The discussion in the previous sections has focused on the options for changes to transmission and distribution demand residual charges. In this section, we set out the options and assessment for the second element in the scope of the TCR SCR, namely changes to the remaining non-locational Embedded Benefits. The term Embedded Benefits is used to describe the different charging arrangements for smaller (sub 100MW) embedded generators (those connected to the distribution network) verses larger generators. Whilst this is part of the same SCR, the issue is somewhat distinct with the focus on the potential harmful distortions as a result of the differences in charges paid or benefits received by generators of different sizes.

6.2. These Embedded Benefits typically arise because these charges are only levied on larger generators and suppliers, with demand charges to suppliers being levied on a 'net' basis at the point the transmission network meets the distribution network (Figure 26). In some cases, suppliers effectively receive a discount on their charges for contracting with smaller embedded generators, the majority of which are passed onto smaller embedded generators in the form of payments from suppliers. In addition, smaller embedded generators can contract with National Grid to receive these payments directly. In other cases, smaller embedded generators avoid charges that larger generators face. The remaining non-locational Embedded Benefits are described in Annex 5.

Figure 26 Net metering at point transmission and distribution networks meet leads to 'Embedded Benefits'



Scope of our review of remaining Embedded Benefits

6.3. We are continuing a process of reform to Embedded Benefits. In July 2016, we set out our concerns with Embedded Benefits in an open letter[60]. We indicated that our most immediate concern was related to the Transmission Demand Residual (TDR) payments to smaller embedded generators, although the other embedded benefits were also a concern we planned to address. We provided an update in December 2016, and in 2017 industry presented proposals for reform via Code Modification Proposals (CMP) 264 and 265. We consulted on our draft Impact Assessment in March 2017, and in June 2017 we decided to approve the option known as WACM 4, to phase out the Transmission Demand Residual Embedded Benefit, via the introduction of the Embedded Export Tariff (EET). The changes were implemented in April 2018, with a phased implementation over three years.

6.4. We said in the TCR SCR launch statement that we are prepared to take further action during the SCR if evidence emerges that the remaining Embedded Benefits create significant distortions to competition and have negative impacts on consumers'

[60] https://www.ofgem.gov.uk/publications-and-updates/open-letter-charging-arrangements-embedded-generation

interests. Our analysis has indicated that there is a sufficient basis for further action, as set out later in Annex 5, and below.

6.5. We are considering reform to three remaining Embedded Benefits which we consider to result in significant distortions. One relates to the Transmission Generation Residual, and two relate to Balancing Services Use of System (BSUoS) charges[61]. and:

a) **Transmission Generation Residual payments**. Smaller embedded generation is not subject to transmission generation residual payments, which are currently negative;

b) **BSUoS charges: payments.** Smaller embedded generators can get paid for helping suppliers reduce their contribution to the costs of balancing the system. Suppliers pass on most of these savings to smaller embedded generators through contractual arrangements and then recover the cost of these payments from other customers. These payments directly add to consumer costs.

c) **BSUoS charges: avoided charges.** Smaller embedded generators[62] also avoid paying generation BSUoS charges, which all other generators connected to transmission and distribution networks are required to pay.

6.6. A related benefit is the reduction in transmission charges for certain small generators, known as the Small Generator Discount. The Small Generator Discount was introduced[63] by the UK Government at the time of BETTA[64] in 2005. The aim of the discount was to create a level playing field between under 100MW 132kV transmission connected generators in Scotland and offshore generators, and those that are distribution connected at 132kV in England and Wales. The expiry date has been extended four times to date, with a current expiry date of 31 March 2019. We will consider the appropriateness of the continuation of this discount in light of potential changes to Embedded Benefits – it may be less appropriate if major Embedded Benefits have been removed. We propose to extend the Small Generator Discount until the three major non-locational Embedded Benefits are removed.

6.7. Differences between forward looking charging and access arrangements between embedded generation and transmission connected generation are being considered within the scope of the Electricity Network Access Project.

6.8. There are other, smaller Embedded Benefits which are lower in value. We have not considered Residual Cash flow Reallocation Cash flow (RCRC) and Assistance for Areas with High Electricity Distribution Charges (AAHEDC) in any detail since they are low in value and hence unlikely to be causing major distortions. Nor are we considering reforms to the treatment of transmission losses. We welcome views on our proposal

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[61] Exporting on-site generation are similarly affected, so references to smaller embedded generation is assumed to include exporting on-site generation.
[62] On-site generation avoid all network charges, including balancing service charges to generators.
[63] https://www.ofgem.gov.uk/sites/default/files/docs/2004/05/6951_9604.pdf
[64] The British Electricity Trading and Transmission Arrangements (BETTA), joined the wholesale market in England & Wales to that in Scotland

not to address this differential treatment. We welcome views on our proposal not to address these smaller Embedded Benefits.

Issue with Embedded Benefits

6.9. Each of the remaining Embedded Benefits represents a difference between the revenues or costs of small embedded generation and larger generation, which does not reflect a difference in the value provided or cost imposer on the system. These are distortions (described in Annex 5), which negatively impact consumers in the following ways.

6.10. The negative Transmission Generation Residual directly increases costs for consumers, as this results in an increased Transmission Demand Residual paid by consumers. It also introduces distortions, making transmission generators more competitive relative to other generators. One example is the Capacity Market, where prices are set by means of an auction through which eligible generation (mainly non-renewable generation) enters bids for the fixed annual payment they require, to either keep open an existing generator or build new capacity. Embedded Benefits that provide additional revenue can distort CM bids, increasing the apparent competitiveness of the generator and hence making this generator more likely to clear in the auction, at the expense of capacity which is more cost-effective.

6.11. The BSUoS Embedded Benefits directly increase the BSUoS that consumers have to pay (by about 20% in total). Consumers have to pay higher balancing charges to make up the payments that these generators receive from suppliers, and also for the charges that these generators do not pay. The increased charges paid by larger generators may be passed through into wholesale electricity prices.

6.12. We believe the distortions outlined above lead to higher consumer costs. More efficient generators could be pushed out of the market, while consumers have to pay additional money to allow suppliers to 'offset' their residual charges. As the amount of money recovered through residual charges is largely fixed over the short to medium term, where these charges are avoided, they will have to be picked up by other users. If they are picked up by generators, they will generally be passed through to consumers through wholesale markets. In addition, inefficient investment in generation connected to either the transmission or distribution networks would lead to inefficient additional network investment, raising costs to consumers.

Options considered

6.13. Our consultation on Access Reform proposed setting up a BSUoS charges task force. Having analysed responses to that consultation, we have asked the ESO to launch a task force to provide analysis to support decisions on the future direction of BSUoS charges.[65] In particular, it will examine the potential and feasibility for some elements of BSUoS being made more cost-reflective and hence provide stronger forward-looking signals, and is due to report its findings in Spring 2019. On conclusion of this work, further consideration can be given to the treatment of any BSUoS charges which will remain principally cost recovery charges. We have therefore limited our consideration

[65] Published alongside this document today

to options which remove the BSUoS Embedded Benefits without changing the overall structure of these charges.

6.14. We have assessed options related to these three remaining Embedded Benefits. For some types of generator these Embedded Benefits may roughly offset one another, but for others, they put smaller embedded generators at a competitive advantage relative to larger generators.

We have considered two reform options for these Embedded Benefits:

a) **TGR & partial BSUoS reform**: TGR reform and removing the ability of smaller embedded generators to receive payments from reducing suppliers' contributions to BSUoS charges.

b) **TGR & full BSUoS reform**: TGR reform, removing the BSUoS payments, and requiring smaller embedded generators to pay BSUoS charges.

6.15. At a high level, removing the BSUoS Embedded Benefits would reduce revenues and increase costs for smaller embedded generators, and reforming the Transmission Generation Residual would reduce revenues for larger generators. Consumers will benefit from these changes from both reduced payments to smaller embedded generators and improved system efficiencies over time.

6.16. Our assessment indicates that a more level playing field between these different types of generator would be reached by removing both Embedded Benefits related to BSUoS charges. However, we have considered the option of only removing the BSUoS payments as well as removing both.

6.17. We have assessed the options for reform of remaining Embedded Benefits using our TCR principles of removing harmful distortions, fairness, and proportionality and practical considerations. To support our principle based assessment, we have considered illustrative generation scenarios, and also commissioned wider system modelling of the policy options.

6.18. We have analysed the net impact of the level of these three Embedded Benefits using four different illustrative generation scenarios.

6.19. The analysis indicates the distortion due to these Embedded Benefits continues to be significant in a number of cases. We can conclude from the analysis that in most cases, the overall Embedded Benefit from these benefits is positive for our illustrative generation types. The details of this analysis and example scenarios can be found in Annex 5.

6.20. The wider system modelling of the policy options for removal of these Embedded Benefits uses the same model as used to assess the reform of transmission and distribution residuals. Further detail on this analysis can be found in the Frontier/LCP report[66].

[66] www.ofgem.gov.uk

6.21. The analysis shows that both options for reform have only modest impacts on system costs (from a reduction of £0.11bn to an increase of £0.16bn). This is due to limited changes in the investment in generation capacity, and the operation of this capacity.

6.22. Both options reduce consumer costs (by between £4.5bn to £6bn for TGR & Full BSUoS reform, and by £3.3bn to £4.1bn for TGR & Partial BSUoS reform). Consumers benefit from reductions in BSUoS charges and Transmission Demand Residual payments. These are partially offset by increases in Capacity Market clearing prices and payments to generators support by CfDs. Generators in these markets increase bids to offset the loss in revenue or increase in costs as a result of the reforms.

6.23. As a group, generators are negatively affected under both options. These impacts are not equally spread across generation types. The majority of the reduction in generator revenues falls on existing renewables supported under the Renewables Obligation (RO). Larger RO supported generation loses out due to the increase in transmission charges, whereas smaller RO supported generation loses out due to the loss of both elements of the BSUoS Embedded Benefit. This is partially a result of the increasing size of the Embedded Benefits over the modelled period.

Treatment of on-site generation

6.24. The proposed reforms to the transmission (and distribution) residual charges and the proposed reforms to the Transmission Generation Residual Embedded Benefit would remove the differential treatment of on-site generation compared to other generation in respect of these transmission residual charges. This is because no forms of generation would pay transmission generation residual charges and no forms of generation would receive payments/benefits from transmission demand charges.

6.25. However, the proposed reforms for BSUoS would leave some potential benefits for non-exporting on-site generation compared to other forms of generation since:

a) Non-exporting on-site generation would continue to benefit from avoiding paying generation BSUoS, alongside avoidance of network and policy costs in general; and

b) Non-exporting on-site generation would continue to receive benefits from helping to reduce demand BSUoS for the site on which it is located.

6.26. In relation to these potential benefits, it is important to note that:

a) exporting on-site generation is similar to similarly-located metered generation (directly connected to the network) from a network usage perspective and receives equivalent treatment under our proposals;

b) non-exporting on-site generation is similar to demand side response from the perspective of network usage and impacts, and in fact cannot usually be discernible from the measured impacts of network usage;

c) displacement effects mean that from the perspective of system operation, a unit of demand reduction has a similar effect as a unit of increased generation in the same location, regardless of whether it is metered or not;

d) it is important that forward-looking charges reflect a user's impact on future network costs and incentivise users to change their behaviour where this will lead to lower costs. Since residual charges need to avoid creating undue distortions, they should not encourage users to take action to avoid paying them.

e) our proposed approach to transmission and distribution residual charges addresses these issues, and if applied to BSUoS charges, would also address these issues in respect of BSUoS charges; and

f) we will consider the recommendations from the BSUoS task force alongside the responses to this consultation in making our final decisions on the proposals set out in this document, and in deciding whether further changes to BSUoS outside of the SCR should take place.

Summary of our assessment

6.27. Our overall assessment is that TGR & Partial BSUoS reform and TGR & Full BSUoS reform both remove harmful distortions and improve cost-reflectivity relative to the baseline of no reform to these Embedded Benefits. The wider system analysis indicates that both options are broadly neutral with regards to system costs. TGR & Full BSUoS reform leads to a greater consumer benefit, which is consistent our assessment that it removes more harmful distortions. The increased benefits to consumers from proceeding with full BSUoS reform rather than partial BSUoS reform is £1.2bn to £1.9bn in present value terms.

6.28. Under both options, some forms of generation will be adversely affected, particularly in the short to medium term. However, we set a clear expectation for the review of the remaining Embedded Benefits within the TCR, and the approach we are consulting on aligns with our decision last year on the largest of the Embedded Benefits. Within that decision (and preceding documents) we clearly stated that benefits gained were inappropriate[67] and that whilst we were prioritising the largest and most immediate issue, we intended to address other Embedded Benefits in due course. The size of the Embedded Benefits have increased over the past few years[68], and are forecast to continue to increase from today's levels if no reforms are made. Hence it is unlikely that the scale of these future revenues were expected when historic investments were made.

6.29. There is a risk that these changes could lead to the cancellation of some projects, including renewable generators which have been awarded CfD contracts and smaller generators which have been awarded CM contracts, which are not yet online and which would face an increase in charges under both of our options. We note that our analysis indicates no concerns with security of supply from our proposed reforms.

6.30. Both options for reform leave in place a residual distortion for on-site generation (when not exporting). This could be resolved in future by charging BSUoS on a similar basis

[67] for example, we stated in our Open Letter on Embedded Benefits (July 2016) that "A negative residual charge prevents generators facing the full costs they impose on the transmission system, effectively subsidising all generators that pay TNUoS charges. We do not consider that this is consistent with the aim of a well-functioning wholesale market "

[68] The Transmission Generation Residual has declined from a positive value and became negative in the 2017/18 charging year, and BSUoS charges have increased from an average £1.50/MWh in 2011/12 to the current value of around £2.33/MWh

as our proposed solution for Transmission and Distribution residual charges. We will consider this when the BSUoS task force has reported its conclusions.

6.31. The differences between TGR & Partial BSUoS reform and TGR & Full BSUoS reform in terms of practicality and cost appear to be small, and are small in proportion to the benefits available. Both options are equally fair in that consumers see reductions in charges in proportion to their usage (either year round or at peak). On this basis we currently propose TGR & Full BSUoS reform, but are consulting on both options, and will consider the findings of the BSUoS charges task force alongside responses to these proposals.

6.32. We have considered the same range of implementation options for the other Embedded Benefits as we have for the wider transmission and distribution residual reform. These are implementation in April 2020, implementation in April 2021, and phased implementation from April 2021 to March 2023. These options are discussed in the following section.

6.33. We are also launching a Statutory Consultation on extending the Small Generator Discount from the current end date of 31 March 2019, for two years until 31 March 2021[69]. We will align this with the timing of our reforms of the remaining Embedded Benefits, and intend to set the Small Generator Discount to zero once our reforms are implemented. If our proposed reforms did not progress, we would maintain the Small Generator Discount until 31 March 2021. Views on the Small Generator Discount should be provided as responses to the Statutory Consultation, which closes on Friday, 4 January 2019.

[69] https:// www.ofgem.gov.uk/publications-and-updates/statutory-consultation-our-proposal-modify-standard-licence-condition-c13-adjustment-use-system-charges-small-generators-electricity-transmission-licence

7. Transitional Arrangements

Section summary

This section sets out the options we have considered how we introduce these reforms. It considers the whole system and consumer benefits and how the implementation options affects these.

Questions for Consultation related to this section. Please provide evidence to support your answers.

14. Do you agree with our proposed approach to transitional arrangements for reforms to: a) transmission and distribution residual charges b) non-locational Embedded Benefits? Please provide evidence to indicate why different arrangements would be more appropriate.

7.1. We understand that the reforms proposed above may have a significant impact on some network users and as such consider it appropriate to consider different arrangements for implementing our proposed reforms. In particular, the transmission and distribution reform options result in some significant changes to residual network charges to final users. Any delay to reform, will delay the associated benefits, and leave in place the distortions and resulting disbenefits. As such we have carefully considered the implications of transitional arrangements and will need to strike a balance between these factors.

7.2. We have also used whole systems modelling to determine how the monetised benefits for consumers and the system overall will change when different implementation dates, transitional periods and sensitivities are applied to the modelling results.

Transitional arrangements for reforms to transmission and distribution residual charges

7.3. We have considered four different implementations:

a) implementation in 2020;

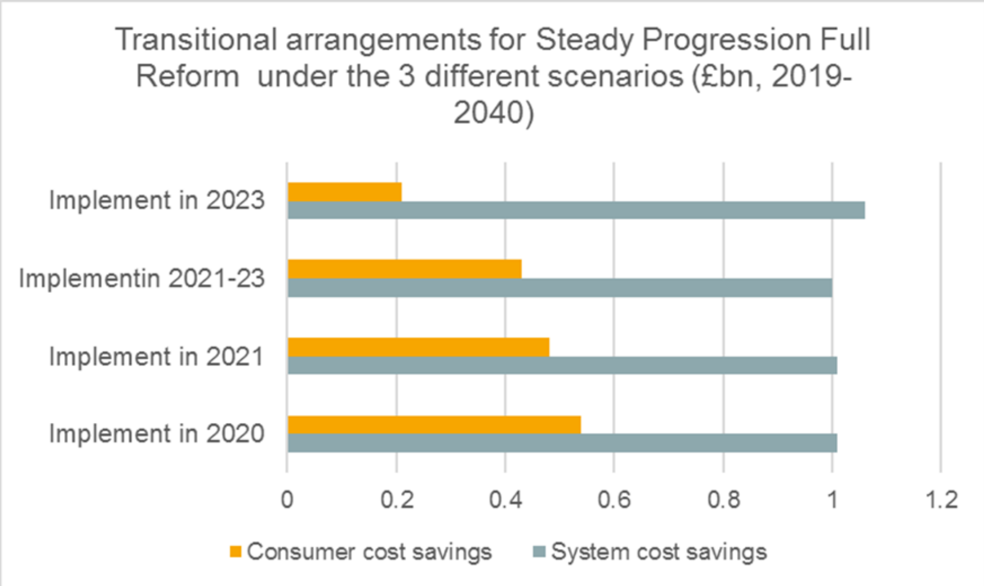
b) implementation in 2021;

c) implementation in 2023; and

d) phased implementation from 2021 to 2023.

7.4. Figure 27 below shows the consumer and system cost savings for the four implementation approaches for Full Reform, compared to the baseline arrangements of no reform, in a Steady Progression background. It demonstrates that savings are achieved in each scenario but that implementation in 2020 offers the maximum consumer and system savings whereas a three-year delay delivers the least savings.

Figure 27 consumer and cost savings for implementation options of full reform compared to baseline under Steady Progression



7.5. We have considered an implementation date of 2020, as this was the earliest that these reforms could be implemented. We have received a wide-range of representations from stakeholders that a 2020 implementation date, whilst technically achievable, is undesirable for a number of reasons.

7.6. Delaying implementation to 2021 would cause less disruption both in terms of industry's charge setting process and how these are passed on to consumers via suppliers. However, it would leave the distortions in place for an additional year.

7.7. Phased implementation from 2021 to 2023 would further soften rate of the change for energy consumers. This would also mean the TCR reforms would come fully into effect during the introduction of RIIO2. However, this approach would add more complexity during the transition period.

7.8. By delaying implementation by three years, more than half of the potential consumer savings are lost. We do not think that this would be in consumers' interests and are not consulting on this option for that reason.

7.9. We are consulting on a both implementation in 2021 and a phased implementation infrom2021 to 2023 for the reforms to transmission and distribution residual charges. Implementation in 2021 would mean consumer savings are reduced by about £0.1 billion, when compared to a 2020 implementation, system savings remain at £1 billion. Phased implementation from 2021 to 2023 would further soften the change for consumers and help with their planning but would create complexity during the transition period.

Transitional arrangements for reform of Embedded Benefits

7.10. We have considered the following implementation options:

a) Implementation in 2020

b) implementation in 2021; and

c) phased implementation from 2021 to 2023.

7.11. Implementation in 2021 would cost consumers an additional £0.5 billion to £0.6 billion compared to implementation in 2020. Within the modelling results, a phased implementation from 2021 to 2023 would cost consumers £1bn compared to a full implementation in 2020 (Table 11). Modelled system cost savings are similar across the three implementation options.

Table 11: Summary of consumer cost impacts[70]

		SP	CR	Cost of delay from 2020: SP	Cost of delay from 2020: CR
2020 implementation	TGR & Partial BSUoS reform	-3.3	-4.1		
	TGR & Full BSUoS reform	-4.5	-6.0		
	Difference	**-1.2**	**-1.9**		
2021 implementation	TGR & Partial BSUoS reform	-2.9	-3.6	0.5	0.5
	TGR & Full BSUoS reform	-4.0	-5.4	0.6	0.6
	Difference	**-1.1**	**-1.8**		
2021-23 phased implementation	TGR & Partial BSUoS reform				
	TGR & Full BSUoS reform	-3.5		1.0	
	Difference				

7.12. We think implementation in 2020 is feasible, and is consistent with our May 2018 open letter on TCR[71]. However, we believe that a 2020 implementation could be quite challenging for some market participants affected by these proposals.

7.13. The benefits to consumers of a 2020 implementation may not be fully realised. This reform is expected to lower wholesale power prices when implemented, and reduce balancing service avoidance payments which are added to consumer bills. Some suppliers will have bought much of their customers' power for the 2020/21 year, so savings through lower wholesale prices (which result from removal of the BSUoS avoidance benefit) may not be passed on to customers. The removal of the BSUoS Embedded Benefits payments would be expected to be mostly passed through to consumers, however, as would savings on transmission charges for demand.

[70] Source: Frontier/LCP. Real 2016 terms
[71] https://www.ofgem.gov.uk/publications-and-updates/ofgem-s-views-following-decision-reject-cmp261

7.14. Implementation in 2021 means suppliers are likely to have purchased a smaller proportion of energy for their customers, meaning it is much more likely that savings through lower wholesale prices will feed through to consumers. However, a one-year delay would lead to additional costs to consumers. It is therefore a trade-off between these factors as to whether these benefits should be removed in 2020 or 2021.

7.15. We have also considered a phased removal from 2021 to 2023. This would align with one of our proposed options for the transitional arrangements for reforms to transmission and distribution residual charging. A phased implementation would manage the impact on generators who are contracted in the CM in the short term. However, there would be almost a four-year gap between indicating our intention to address Embedded Benefits (in 2016) and an implementation of 2020 (and a five-year gap if implementing in 2021). Hence we do not consider a longer implementation than this is warranted.

7.16. Given our discussion above that Embedded Benefits are increasing in size and are unlikely to have been factored into business models for historic investment decisions, we do not believe that grandfathering of Embedded Benefits is appropriate. This would impose significant additional costs on consumers.

7.17. For residual transmission and distribution charges, part of our reason for recommending a phased implementation for the longer term solution is that some of the distributional impacts on similar consumers (those within the same customer segment but with differing levels of consumption) are significant and hence a managed change is beneficial in allowing the affected users to adjust. For the remaining Embedded Benefits, similar consumers will see the same effect.

7.18. Delaying implementation of removal of the Embedded Benefits to 2021 would cause less disruption both in terms of industry’s charge setting process and how these are passed on to consumers via suppliers. However, it would leave the distortions in place for an additional year. Hence we are consulting on 2020 and 2021 implementation for the reforms to Embedded Benefits.

7.19. We are seeking views on these implementation timescales.

8. Our 'minded to' position

Section summary

This section sets out our minded to decision:

- that we consider that transmission and distribution residual charges in the form of segment-specific fixed charges, set using the use of net system volumes for each segment, are the most consistent with the TCR principles. We consider implementation from April 2021, either with or without phased implementation to April 2023, is most appropriate.
- we propose to address the most significant remaining non-locational Embedded Benefits (with TGR and full BSUoS reform), with implementation in either April 2020 or April 2021.

Questions for Consultation related to this section. Please provide evidence to support your answer.

15. Do you agree with our minded to decision set out? If not please state your reasoning and provide evidence to support your answer.

16. For our preferred option do you think there are practical consideration or difficulties that we have not taken account of? Please provide evidence to support your answer.

Our assessment

8.1. We found that less distortionary arrangements are most likely to be served by charges that do not afford individual users the ability to reduce their contribution to residual charges, by changing their behaviour or investing in equipment or techniques for managing charges. This behaviour is likely to lead to inefficient investment and an unfair burden of charges falling on those who are unable to manage their exposure to residual charges. We think that less distortionary arrangements are best facilitated for all users through the Fixed Charges option.

8.2. We consider it to be important from a fairness and proportionality perspective for charges to be justifiable and appropriate for a range of possible future outcomes. The means for determining the fixed charges should use existing industry arrangements where possible to minimise the need for new ones to be established. The basis should also require the minimum possible regulatory choices.

8.3. We also consider that the basis for fixed charges should ensure that all users make a fair contribution but at the same time keeps redistribution of revenues to a minimum.

We consider that the use of net system volumes by segment reflects an equitable distribution of revenue according to an established measure of system use, but does not provide an individual residual charging benefit for users who can reduce their use of the system (as net volumetric charges would do). This approach also provides a relatively small redistribution compared to capacity or gross volumetric distributions, which allocate significantly more revenue to domestic and industrial users respectively.

Minded to decision – Network Residual Charges

8.4. Our minded to position is that Transmission and Distribution residual charges should take the form of the Fixed Charges option. We think these should take the following form-

a) A separate fixed charge payable for each demand meter.

b) All final demand users should pay fixed charges. Using current practise, users should pay residual charges for the voltage level at which they are connected and those levels with higher voltages.

c) Distribution fixed charges shall be set separately for each DNO, in order to account for the different residual charge requirements that follow from separate allowed revenues and forward-looking charges revenues.

d) Fixed charge segments for recovering distribution residual revenues shall be set separately for a number of segments. The extra high voltage levels should form a single segment. For the high voltage and low voltage voltage levels (ie for CDCM customers), LLFCs shall be used to further segment these customers. A single charge be produced for extra high voltage users. A single charge should then be produced for each of the LLFCs. For each DNO, the proportion of charge allocated to each LLFC or to the extra high voltage level should be based on that segments overall contribution to net volumes on that distribution network.

e) Fixed charge segments for recovering transmission residual revenues shall be set separately for a number of segments. The extra high voltage levels should form a single segment, and the transmission voltage level another. For the high voltage and low voltage levels (ie for CDCM customers), Line Loss Factor Class (LLFCs) shall be used to further segment these customers. A single charge be produced for extra high voltage users, and a single charge should group all transmission connected users. A single charge should then be produced for each segment defined by the LLFCs. The residual charge for each segment is determined by the proportion of the volume that segment consumes as a proportion of total consumption. The proportion of charge allocated to each LLFC or to the extra high voltage or transmission voltage levels should be based on that segments overall contribution to net volumes on the transmission networks.

Implementation

8.5. Under normal practice, charging changes would be expected to be implemented, in the next possible charging year. We consider that, while immediate implementation would usually be preferable, there remains significant industry engagement and workgroup analysis to be carried out before our preferred option or any similar option could be implemented. We think that these factors mean that 2021 is the earliest feasible implementation date for changes to transmission and distribution residual charges.

8.6. We also recognise there are distributional impacts that will come about from reform, and while we believe these will lead to a fairer, less distortive regime, we will consider that there may be justification for transitional arrangements. In particular, we believe a period of phased implementation where the existing regime is replaced over a number of years may reduce the distributional impacts on large users and on low-consuming vulnerable users, although we recognise this will slow the rate at which benefits are felt by other users and will retain distortion for longer. It will also mean more complex arrangements over these years, which some participants may prefer to avoid.

8.7. We are therefore consulting on two options, either;

a) full implementation from April 2021, or

b) implementation from April 2021 with a phasing period (with changes fully implemented in April 2023).

Minded to decision - Remaining non-locational Embedded Benefits

8.8. Both of our options for reform TGR & Partial BSUoS reform (removing two of the three Embedded Benefits under consideration) and TGR & Full BSUoS reform (removing all three) both remove harmful distortions and improve cost-reflectivity relative to the baseline of no reform to remaining Embedded Benefits.

8.9. The wider system analysis indicates that both options are broadly neutral with regards to system costs. TGR & Full BSUoS reform leads to a greater consumer benefit, which is consistent our assessment that it removes more harmful distortions. The differences between TGR & Partial BSUoS reform and TGR & Full BSUoS reform in terms of practicality and cost appear to be small, and are small in proportion to the additional benefits available.

8.10. On this basis we currently propose TGR & Full BSUoS reform, but are consulting on both options, and will consider responses alongside the findings of the BSUoS charges task force.

8.11. We are proposing to make the following decisions -

a) Charge suppliers BSUoS using gross demand at GSP, having the effect of removing the BSUoS Embedded Benefit. Implemented in either April 2020 or April 2021.

b) Charge BSUoS Charges to Small Embedded Generation, implemented in either April 2020 or April 2021. We propose to direct the ESO to raise the relevant CUSC modification. This will be dependent on the TGR & Full BSUoS reform continuing to be our preferred option.

c) Set the Transmission Generation Residual to zero, subject to maintaining compliance with 838/2010. The ESO is developing a modification which would enact the post CMP 261 definition of the 838/2010 range, and would allow us to direct that our policy position of no residuals charged to generation is met.

d) Launch a Statutory Consultation to extend the Small Generator Discount from the current end date of 31 March 2019 to a revised end date of 31 March 2021, with the intention that this will be set to zero once the changes set out above are implemented. Views on the Small Generator Discount should be provided as responses to the Statutory Consultation, which closes on Friday 4 January 2019.

9. Consultation questions and how to respond

1. Do you agree that residual charges should be levied on final demand only?

2. Do you agree with how we have assessed the impacts of the changes we have considered against the principles? If you disagree with our assessment, please provide evidence for your reasoning.

3. For each user, residual charges are currently based on the costs of the voltage level of the network to which a user is connected and the higher voltage levels of the network, but not from lower voltage levels below the user's connection. At this stage, we are not proposing changes to this aspect of the current arrangements. Are there other approaches that would better meet our TCR principles reducing harmful distortions, fairness and proportionality and practical considerations?

4. As explained in paragraphs 4.41, 4.43, 4.46, 4.49, 4.80, we think we should prioritise equality within charging segments and equity across all segments. Do you agree that it is fair for all users in the same segment to pay the same charge, and the manner in which we have set the segments? If not, do you know of another approach with available data which would address this issue? Please provide evidence to support your answer.

5. Do you agree that similar customers with and without on-site generation should pay the same residual charges? Should both types of users face the same residual charge for their Line Loss Factor Class (LLFC)?

6. Do you know of any reasons why the expected consumer benefits from our leading options might not materialise?

7. Do you agree that our leading options will be more practical to implement than other options?

8. Do you agree with the approaches set out for banding (either LLFC or demanding for agreed capacity)? If not please provide evidence as why different approaches to banding would better facilitate the TCR principles.

9. Do you agree that LLFCs are a sensible way to segment residual charges? If not, are there other existing classifications that should be considered in more detail?

10. Do you agree with the conclusions we have drawn from our assessment of the following?

a) distributional modelling
b) the distributional impacts of the options
c) our wider system modelling
d) how we have interpreted the wider system modelling?

Please be specific which assessment you agree/disagree with.

11. Do you agree with our proposed approach to the reform of the remaining non-locational Embedded Benefits?

12. Do you agree with our proposal not to address any other remaining Embedded Benefits at this stage? Which of the embedded benefits do you think should be removed as outlined in xx? Please state your reasoning and provide evidence to support your answer.

13. Are there any reasons we have not included that mean that the remaining Embedded Benefits should be maintained?

14. Do you agree with our proposed approach to transitional arrangements for reforms to: a) transmission and distribution residual charges b) non-locational Embedded Benefits? Please provide evidence to indicate why different arrangements would be more appropriate.

15. Do you agree with our minded to decision set out? If not please state your reasoning and provide evidence to support your answer.

16. For our preferred option do you think there are practical consideration or difficulties that we have not taken account of? Please provide evidence to support your answer.

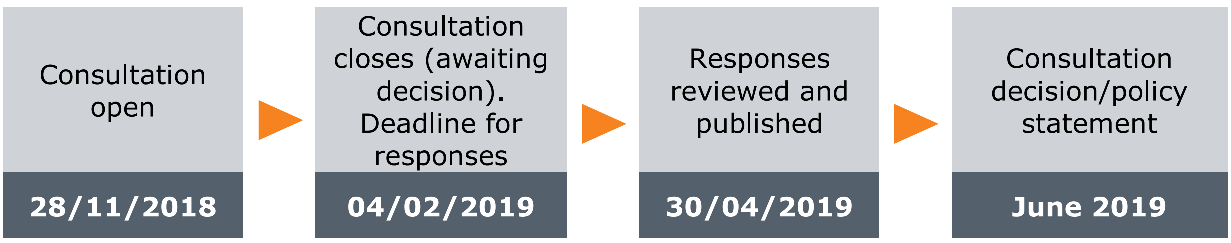
Consultation stages

This document marks the start of a consultation period ending on, which starts on 1 February 2019. During this time, respondents are invited to provide feedback on our impact assessment and minded- to position. Details on how to respond to this consultation, including contact details for any queries can be found below. It also gives a complete list of the questions which we are specifically seeking respondents' views on, although we welcome respondents' views on any aspect of this document.

We aim to hold a Charging Futures Forum in which we will discuss the consultation and the analysis in January 2019. We will send an invitation to interested stakeholders via our website once we have finalised a date for this.

We will consider any responses to this consultation before reaching its decision on the options. We expect to reach a final decision in mid-2019.

Figure 1: Consultation stages



How to respond

Section summary

This section explains how you can respond to this consultation and make your views about our minded to position known to us, supported by any evidence which you believe supports you views. Please read it carefully and follow the instructions given.

We want to hear from anyone interested in this consultation. Please send your response to the person or team named on this document's front page.

We've asked for your feedback in each of the questions throughout. Please respond to each one as fully as you can.

We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations.

Your response, data and confidentiality

You can ask us to keep your response, or parts of your response, confidential. We'll respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose. If you do want us to keep your response confidential, please clearly mark this on your response and explain why.

If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you *do* wish to be kept confidential and those that you *do not* wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we'll get in touch with you to discuss which parts of the information in your response should be kept confidential, and which can be published. We might ask for reasons why.

If the information you give in your response contains personal data under the General Data Protection Regulation 2016/379 (GDPR) and domestic legislation on data protection, the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on consultations, see Appendix 4.

If you wish to respond confidentially, we'll keep your response itself confidential, but we will publish the number (but not the names) of confidential responses we receive. We won't link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits without undermining your right to confidentiality.

General feedback

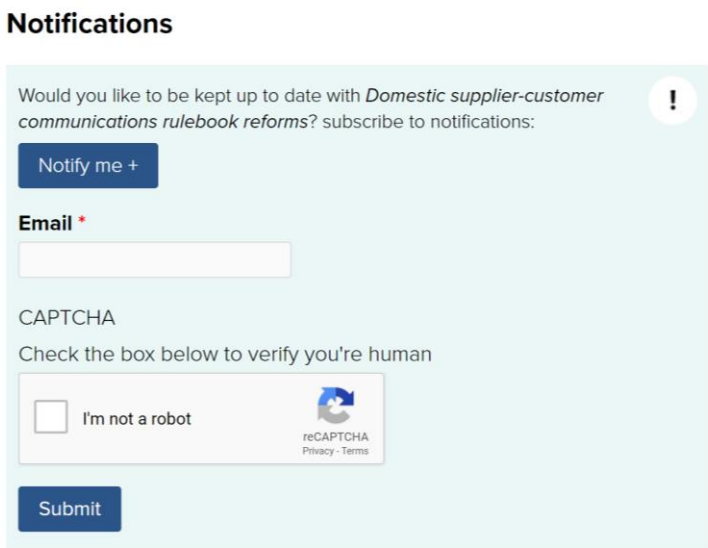
We believe that consultation is at the heart of good policy development. We welcome any comments about how we've run this consultation. We'd also like to get your answers to these questions:

1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

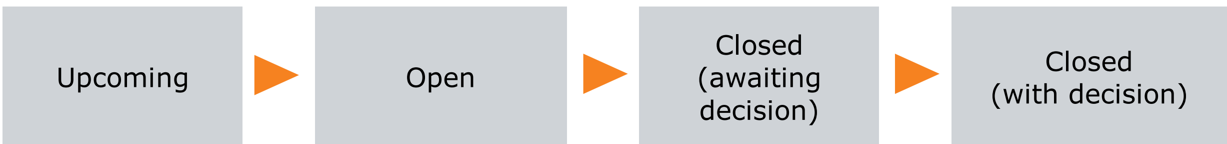
Please send any general feedback comments to stakeholders@ofgem.gov.uk

How to track the progress of the consultation

You can track the progress of a consultation from upcoming to decision status using the 'notify me' function on a consultation page when published on our website. Ofgem.gov.uk/consultations.



Once subscribed to the notifications for a particular consultation, you will receive an email to notify you when it has changed status. Our consultation stages are:



Appendixes

Delete this box when producing your document.
Instructions: Place technical or supporting information in the appendix.

Index

Appendix	Name of appendix
1	TCR principles
2	Stakeholder research
3	Academic research and international comparators
4	Assessing the Options
5	Non-locational Embedded benefits
6	Large users
7	The draft impact assessment
8	Current Charging Arrangements and residual allocation

Privacy notice on consultations

Personal data
The following explains your rights and gives you the information you are entitled to under the General Data Protection Regulation (GDPR).

Note that this section only refers to your personal data (your name address and anything that could be used to identify you personally) not the content of your response to the consultation.

1. The identity of the controller and contact details of our Data Protection Officer
The Gas and Electricity Markets Authority is the controller, (for ease of reference, "Ofgem"). The Data Protection Officer can be contacted at dpo@ofgem.gov.uk

2. Why we are collecting your personal data
Your personal data is being collected as an essential part of the consultation process, so that we can contact you regarding your response and for statistical purposes. We may also use it to contact you about related matters.

3. Our legal basis for processing your personal data
As a public authority, the GDPR makes provision for Ofgem to process personal data as necessary for the effective performance of a task carried out in the public interest. ie a consultation.

3. With whom we will be sharing your personal data
(Include here all organisations outside Ofgem who will be given all or some of the data. There is no need to include organisations that will only receive anonymised data. If different organisations see different set of data then make this clear. Be a specific as possible.)

4. For how long we will keep your personal data, or criteria used to determine the retention period.
Your personal data will be held for ***(be as clear as possible but allow room for changes to programmes or policy. It is acceptable to give a relative time eg 'six months after the project is closed')***

5. Your rights
The data we are collecting is your personal data, and you have considerable say over what happens to it. You have the right to:

- know how we use your personal data
- access your personal data
- have personal data corrected if it is inaccurate or incomplete
- ask us to delete personal data when we no longer need it
- ask us to restrict how we process your data
- get your data from us and re-use it across other services
- object to certain ways we use your data
- be safeguarded against risks where decisions based on your data are taken entirely automatically
- tell us if we can share your information with 3rd parties
- tell us your preferred frequency, content and format of our communications with you
- to lodge a complaint with the independent Information Commissioner (ICO) if you think we are not handling your data fairly or in accordance with the law. You can contact the ICO at https://ico.org.uk/, or telephone 0303 123 1113.

6. Your personal data will not be sent overseas (Note that this cannot be claimed if using Survey Monkey for the consultation as their servers are in the US. In that case use "the

Data you provide directly will be stored by Survey Monkey on their servers in the United States. We have taken all necessary precautions to ensure that your rights in term of data protection will not be compromised by this".

7. Your personal data will not be used for any automated decision making.

8. Your personal data will be stored in a secure government IT system. (If using a third party system such as Survey Monkey to gather the data, you will need to state clearly at which point the data will be moved from there to our internal systems.)

9. More information For more information on how Ofgem processes your data, click on the link to our "Ofgem privacy promise".