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Targeted Charging Review
Energy Systems Transition
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4th February 2019

Dear Andrew

Targeted Charging Review: Minded To Decision and Draft Impact Assessment

Please find attached our response to the Targeted Charging Review Consultation. In summary:

We agree with Ofgem's minded to decision on Residual Charges. The fixed charge option is the most practical approach and can be implemented relatively easily since it uses readily available historical volume data. We would suggest a single fixed charge for both domestic unrestricted and domestic Economy 7 customers. We see no reason to differentiate between the 2 types of domestic customers for residual charging.

The Capacity Option is not a viable option for domestic customers. We believe it should not be considered further. Not only would it be impractical to implement (the need for costly additional industry data flows and new processes to manage the data), the methodology of deeming domestic, and also small non-domestic capacities, could lead to large swings in tariffs if capacities for such small customers are over or underestimated. Business customers would therefore either be paying too little or too much purely as a consequence of the methodology.

We have raised in our response our observation that the segments from the fixed charge method for half hourly metered business customers can hold a significantly wide range of customers. Should Ofgem wish to provide additional segmentation within each fixed charge category, we believe our suggested fixed : capacity hybrid method (for half hourly metered business customers only) would be a practical way to do this.

Implementation should be aligned to the introduction of the changes to Forward Looking Charges - which are inextricably linked. There should also be phasing over 3 tariff years. The timescales should also align to ensure DNOs continue to provide 15 month's notice of DUoS charges.

We agree that residual charges should be charged to demand.

While recognising the benefits to demand customers, we have concerns at the proposal to start charging BSUoS to embedded generators. We do not support the full BSUoS reform due to the impact on existing embedded generation. Although Ofgem have been signalling reduction in embedded benefits in recent years the introduction of BSUoS charges for generation is unexpected. We do not believe that charging BSUoS has been signalled to date. The introduction of such a regime might seriously undermine the commercial and investment case for existing generation assets. We also believe that it will impact the development of new renewable generation.

We would encourage a cautious approach when considering applying a charge for BSUoS on to distributed generation (DG), given that typically a large proportion of Balancing Services costs are driven by Transmission connected generation. So while we understand that all costs borne by Transmission connected assets will ultimately be passed on to the consumer, it is rather an implausible stretch for DG to be considered an appropriate target to carry BSUoS costs.

We would be keen to arrange a meeting with you and your colleagues to discuss the contents of our consultation response further.

Yours sincerely

Helen Inwood

Helen Inwood

(by email so unsigned)

Non-Commodity Charging Manager

CONSULTATION RESPONSE

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

Yes, we 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.

Yes, we agree with Ofgem's assessment against the principles for residual charges.

However, we do not believe that such rigorous analysis has been applied for the proposed changes to embedded benefits.

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?

We agree that Ofgem should keep the current arrangements. We would not support users also paying for voltage levels below their connection..

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.

Please see our response to Questions 7 & 8 for further details.

- The fixed charge approach is a fair, practical way to allocate segments. The data is already available and is maintained. This approach is already successfully used in the DUoS CDCM charging methodology.

- <u>We would suggest that all domestic users, regardless of metering (unrestricted or E7), should be treated as one segment and should all pay the same residual charge.</u>

- <u>We do **not** agree that domestic customers should be split further by high / medium / low capacity.</u> Such a solution would be impractical to implement in the timescales that Ofgem are suggesting since it would need new data items and flows to identify which customer fell into which banding, as well as a new process to manage changes of customer usage. From a point of principle, can it really be justified to charge one house a higher fixed charge than the one next door based on a deemed (unknown) capacity? They are both using the same part of the network. Even if one house has facilities to connect an electric vehicle etc, it may not be used or there could be a usage change (e.g. the previous electric car owner moves out and another moves in but does not use the car supply point). We would therefore urge Ofgem to consider that all domestic customers are treated as a single segment for residual charging.

- <u>For larger half hourly metered business customers, we agree that the fixed charge approach does satisfy Ofgem's objectives of charging all users the same residual charge within a segment.</u> However, we are conscious that some of the fixed charge kWh consumption bandings are quite diverse in our business portfolio. Under the fixed charge approach, customers with lower than average consumption within their segment will pay relatively more than customers with higher than average consumption in their segment.

- <u>*Should Ofgem decide that more sub-banding is required to address the wide banding within a segment issue more fairly, we would suggest a hybrid approach between the fixed and capacity method for larger half hourly business customers who have an Agreed Supply Capacity is an easy and reasonably practical approach to implement.*</u>
    - *i.e. the fixed method is used to allocate the total revenue for the all segment pots (including domestic).*
    - *For the half hourly metered business segments (who have agreed supply capacities), rather than then dividing the revenue £ by the number of mpans in the segment pot to calculate the £/mpan rate, the revenue £ is divided by the total capacity in the segment to calculate a £/kVA rate.*
    - *The resultant £/kVA rate would then be applied to each customer's contracted capacity (the ASC kVA as per their DNO connection agreement) . Smaller customers within a given segment will therefore pay a lower, but proportionate charge than larger customers.*
    - *Domestic consumers are charged on the fixed charge approach only.*

- We recognise that this above hybrid fixed : capacity model for business customers does provide scope to avoid some residual charges if consumers elect to reduce their contracted capacity. This is clearly something that Ofgem are looking to address. However, the approach may provide the following benefits:
    - If business customers are encouraged to review and reduce their Agreed Supply kVA (effectively handing 'hoarded capacity' back to the DNO) then the consequential benefits are tangible, both in terms of DNO planning and consenting for new

connections but also reducing the risk of unnecessary reinforcement works. This £/kVA modelhas the potential to provide tangible benefits to the whole system.

- An ASC based £/kVA charge could encourage diligent customers to enact energy efficiency measures to reduce their overall consumption (and also peak demand), which would bring further benefits to GB plc

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)?

Yes, we agree that similar customers with and without onsite generation should pay the same residual charges. Line loss factor class is a good way to allocate these charges - it is already used in DUoS charging, the data is available and well maintained.

However, we are concerned that the Forward Looking Charges are not currently cost reflective for customers with and without on-site generation. We would therefore urge Ofgem to implement the changes to Residual Charges at the same time as the forward looking charges so that customers can respond to the appropriate signal and make investment decisions on that basis.

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

As with all forecasts "outturn may well be different to forecast". However referring to the Frontier analysis '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'. In addition to CM escalation risk we believe that there will be a number of other dynamics which could undermine confidence in the expected consumer benefits case:

For many years the significant Time of Use (ToU) price signals associated with TNUoS/Triad have encouraged change of behaviour. As this ToU elements will soften post-TCR implementation Ofgem should consider:

- National Grid typically enjoy the benefits of ~2GW (2000MW) of Customer Demand Management (CDM) throughout the Triad season, with ~30/35 periods where tangible load management / behind the meter generation[1] can be detected by National Grid

[1] Noting also that Ofgem appear to favour large thermal plant on the basis that it is 'more efficient than smaller demand-side generation (DG)'. However it should be noted that (a) due to the need, across the winter-peak to call on less clean, less efficient plant as we work through the price stack (still including coal plant at >900g Carbon / kWh) and (b) a generator behind the meter is perfectly located – i.e. by the nature of

- Capacity Market (CM) volume / price dynamics: it would be reasonable to expect the Capacity Market Clearing Price to increase since

    - Low-priced CM assets using Triad benefit as part of their commercial return will need to revise their bidding strategy and/or may be displaced by larger thermal plant;

    - Additional CM Capacity may be required as a result of the loss of a percentage of the winter Triad-related Customer Demand Management (which would result in the GB GW peak demand increasing).

    - As a consequence the price paid by all customers, through the Capacity Market Obligation charges (recovered 1600-1900 Mon-Fri, Nov-Feb) would continue to rise and potentially escalate rapidly post TCR.

- Wholesale Market prices will potentially increasing as more conventional thermal generation[2] is required as a result of the loss of Triad-related CDM. This price effect can be compounded if EU power is traded (exported) across the interconnector during times of GB stress[3].

- Balancing Services costs (and resultant BSUoS) paid by customers are predicted to recover as a consequence of the TNUoS ToU review. As a result owners of assets who bid in to the various Response and Reserve markets will need to consider their bidding strategies to address the loss of TNUoS value.

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its position 'behind the meter' it avoids both transmission and distribution losses which could exceed 10%/12% in total, depending on location/voltage of the customer's connection (so a large Transmission connected generator would have to produce 110MWhs of power to supply 100MWhs of customer demand).

[2] The GB peak tends to occur during winter evening peaks, when there is zero solar PV and often when wind speeds are very low, therefore conventional generation will be required depending on price merit.

[3] It is not unusual for any enduring cold spells in the UK to also be felt across Europe and with France and Belgium having limited capacity beyond their nuclear fleets can result in UK power being exported, resulting in a compound effect on GB wholesale market prices.

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

For any solution to be practical to implement, we believe it should use data that is already available in the Industry. This should avoid the need for new data, at potentially customer site level, and new, potentially costly data flows. Our views on the practicalities of the two leading options are below:

The Fixed Charge Approach:

We agree that the preferred option - the fixed charge approach - is the most practical approach. It is relatively easy to implement by all parties since it is based around LLFC, a data item that is already used in practice for DUoS charging.

The need for costly new industry data flows is reduced. The main change under the fixed charge approach is that National Grid SO will need additional details of volume and customer numbers by LLFC by DNO since they do not currently receive data at that level for industry billing purposes. This information is already available within the industry - processes around that information transfer will need to be designed and implemented (e.g. it should be based on historical data, timescales for which are clearly defined. Our preference would be that DNOs and NG SO use the same snapshot of the data for consistency across DUoS and TNUoS methodologies). We would not expect this to be a hugely complicated task and would not anticipate large costs to change industry billing systems.

The Capacity Approach

As per our response to Question 4 & 8, we believe that a Capacity approach would be practical for larger sites, typically half hourly metered customers, who have an agreed capacity level with their DNO. This information is widely used in calculating DUoS charges. We would suggest that the management of this information would need to be tightened up to ensure that any changes to the agreed capacity level is updated more quickly than in the current process.

However, the suggested high / medium / low Deemed Capacity for Domestic Customers does not work in practice. We do not think this is a viable practical option for this sector and would urge Ofgem to reconsider this as a feasible solution.

- The consultation proposal is suggesting that there could be 3 chargeable bands for domestic customers capacity - low 4KVA (75%), medium 6KVA(15%) and high 8kVA(10%). There is an overarching issue which affect the viability of this option for domestic customers.
- While it is certainly feasible to calculate residual rates using high level assumed proportions for the capacity mix, the suggested methodology hits a practical problem when it comes to then trying to provide accurate billing by the industry to suppliers. It will also cause a similar problem for supplier billing domestic customers – and for the Ofgem price cap.
- There is currently no industry wide data or mechanism to easily identify a domestic customer's capacity. Everything in the industry is done on a volume basis for domestic. The information

currently received by the DNO currently is a total consumption by half hour for profile class 1 and 2 in each LLFC. Unless a new data flow was introduced which correctly tagged customers to the correct band (and was maintained as customers changed their behaviour), it would be impossible to identify which capacity banding a domestic customer should be allocated to. Without this additional flow, DUoS and TNUoS industry billing to suppliers would not be accurate.

- Under the consultation proposals, there would be 3 variations of the domestic unrestricted and E7 tariffs – low, medium and high user – each with a different fixed charge. Without an additional data item to tag domestic customer's capacity, a supplier would not know which tariff to put a customer on since they have no means to identify their banding. In addition, if given a choice (e.g. on a broker or supplier website), it is highly likely all customers would look to select the lower of the 3 rates. Can it be justified to charge one house a higher fixed charge than the one next door? They are both using the same part of the network. Even if one house has facilities to connect an electric vehicle etc, it may not be used or there is usage change (e.g. the previous electric car owner moves out and another moves in but does not use the car supply point).
- From a price cap point of view, there would need to be 3 domestic tariffs per domestic category instead of the current 1 tariff per category. Again, it would be difficult for a supplier to know how to split these customers out across the 3 new tariffs since domestic capacity cannot be easily identified.
- Implementation of a new data flow to enable the capacity option to work would be time consuming and costly, leading to multiple industry and supplier system changes.

The deemed capacity for small non-domestic and domestic customers has a further issue. If the values and splits are updated every year, <u>all customers could potentially see large swings in the residual part of the charge, simply due to the nature of the deemed capacity methodology and inherent inaccuracy of the deemed value.</u> If the values were deemed too low, larger customers would be paying more than they should; if the values were deemed too high, larger customers would be paying less than they should. There is clearly uncertainty around the true values of domestic capacity. For example, we note that the Frontier analysis assumes a domestic capacity of 18kW. Yet in the consultation, capacity is expected to be in the range of 4kW-8kW.

<u>In summary</u>

- <u>We are very concerned that the Capacity approach is not practical for domestic customers and would cause a great deal of complexity to try to implement.</u> It is impractical from an industry billing supplier and supplier billing customer perspective since the size of customer cannot easily be determined. To implement this properly would require a new data items which flagged every domestic customer's charging band – and a mechanism for that to be changed as customers change their behaviour. This would be costly and time consuming.

- <u>The Capacity method could be implemented for larger business customers who already have an agreed supplied capacity. Some additional processes to manage this information better</u>

when a customer renegotiates their agreed supply capacity with the DNO would need to be implemented.

- The Fixed Charge is the most practical of the three options since it would mirror the method already used for DUoS billing.

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.

Please see also our responses to **Questions 4, 7 and 9**

(a) The LLFC Approach For Banding:

We fully support the LLFC approach for fixed charge banding. It is simple, uses current industry data and processes and will allocate residual charge using historical data. It is clear and easy to implement. The LLFC Fixed Charge meets the Ofgem principle that customers cannot avoid paying the fixed charge.

We believe it is Ofgem's intention that the LLFC banding should mirror exactly what is currently done for Distribution Use of System Tariff. *(Please see our answer to Question 9 which clarifies the approach we believe is needed if there are multiple LLFCs within a DNO tariff).*

Ofgem may, however, wish to consider whether or not the resulting LLFC banding is could be improved upon for certain customer groups? Certain modifications could be made, while keeping the underlying LLFC approach for fixed charge banding, to perhaps make the bandings more reflective of different types or sizes of customers?

Domestic Customers:

The consultation currently suggests that a domestic unrestricted customer should pay a different residual charge to a domestic two rate customer. This seems unfair since we do not see many differences between the two customer types. Indeed, many 2 rate customers may have asked their supplier to combine the registers and bill them as a one rate, while keeping the 2 rate meter which is used for settlement purposes. We would suggest that Domestic Unrestricted and Domestic Two Rate segments should be combined into a single overall domestic group for the fixed charge approach i.e. domestic unrestricted and domestic E7 would all pay the same fixed residual charge.

Non-Domestic Customers

The fixed charge approach as currently stated seems appropriate.

Larger half hourly business customers with Agreed Supply Capacity:

As per our response to **Question 4**, there are a wide range of customer types within each LLFC group. For example, analysis on our own customer base shows that for HV half-hourly, customers can range between 64 kVA and 18000 KVA in one DNO region. Is it appropriate to charge everyone the same residual fixed charge within that banding given the wide range of customers within that band? If it is decided by Ofgem that there does need to be further sub-banding of the fixed charge segment, we would suggest a hybrid approach between fixed and capacity method could be applied to give the additional granularity i.e. the fixed method is used to allocate the total revenue for the segment pot. However, rather than then dividing the revenue £ by the number of mpans in the segment pot to calculate the £/mpan rate, the revenue £ is divided by the total capacity in the segment to calculate a £/kVA rate. This rate is then applied to each customer's capacity. Smaller customers within the segment will therefore pay a lower charge than larger customers. We recognise that this does provide scope to avoid some residual charges by reducing capacity – however, this needs to be weighed up against whether or not the basic fixed charge approach provides an appropriate band over which residual fixed should be applied.

EHV customers

As with larger half hourly business customers, we would suggest that the initial part of the fixed charge approach i.e. allocation of the revenue pot could be applied to EHV. However, it may appropriate to then allocate the residual charges on a customer level within that group given the wide ranging nature of these sites.

(b) The Capacity Approach for Banding

As per our answer to Question 7, we do not believe that the deemed capacity approach works for either domestic or non-domestic. If the values and splits are updated every year, all customers could potentially see large swings in the residual part of the charge, simply due to the nature of the deemed capacity methodology and inherent inaccuracy of the deemed value. If the values were deemed too low, larger customers would be paying more than they should; if the values were deemed too high, larger customers would be paying less than they should. There is clearly uncertainty around the true values of domestic capacity. For example, we note that the Frontier analysis assumes a domestic capacity of 18kW. Yet in the consultation, capacity is expected to be in the range of 4kW-8kW.

In addition, the consultation suggests a high / medium / low capacity for domestic. This is unpractical – such a banding is not currently measurable for suppliers, DNOs or National Grid SO and would require additional data flows to implement. This approach should be discounted for domestic customers on the basis that it would be too difficult to implement in the timescales Ofgem are proposing and costly.

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?

Yes. We fully support using LLFC as a sensible way to segment residual charges. It is data commonly used across the industry, the approach is proven and the data is fully maintained.

We believe the above is Ofgem's intention in the TCR to use the LLFC in the same way that it is used in DUoS. It is not entirely clear in the current consultation how multiple LLFCs within a distribution tariff are handled. We would suggest that this approach should be clarified in the final decision document. i.e.

Many DNOs e.g. Yorkshire have a 1:1 relationship between LLFC and DUoS tariff. Under this scenario, the LLFC = DUoS tariff group.

However, some DNOs have a multiple LLFCs within the DUoS tariff e.g. Manweb Domestic Unrestricted has LLFCs of 101 and 102 associated to it. To provide clarity, under the fixed charge approach, customers in the Manweb area with LLFCs of 101 and 102 should be grouped under the same Domestic Unrestricted segment i.e. it is the 'LLFC grouping' is that used for the Distribution Use of System tariff, not individual LLFC. The LLFC is the key field to use to identify the grouping into customer segment and we support using it. This approach for grouping together customers is already used in DUoS tariffs.

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.

As per our response to **Question 6** (referring to 'expected consumer benefits') the wider system modelling does not appear to have been considered well at all. Furthermore the perception in the market is that there is a lack of an overarching strategy and a potential bias towards an agenda driven by large, centralised thermal generation – investment in demand side flexibility (DG, storage and conventional load response) is essential in the scenarios outlined by the ENA's Open Networks project and National Grids Future Energy scenarios. Unless these models accurately consider the wider ramifications of the changes and can be considered fit for an enduring period then we risk considerable damage to both investor confidence and also an unnecessary, uncontrolled escalation of peak power demand and associated costs.

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

We do not support the full BSUoS reform due to the impact on existing embedded generation. Although Ofgem have been signalling reduction in embedded benefits in recent years the introduction of BSUOS charges for generation is unexpected. We do not believe that charging BSUOS has been signalled to date. The introduction of such a regime might seriously undermine the commercial and investment case for existing generation assets. We also believe that it will impact the development of new renewable generation.

We support the Ofgem principles of removing distortions in the market but are keen that the "fairness" principle is met too. Therefore if reform is required this should be partial BSUOS reform. We believe that this will be beneficial to customers whilst reducing the impact to distribution-connected generators and the investment cases they were built upon. This will be in harmony with Ofgem's previous announcements.

It should be noted that a lot of embedded generators are initially supported by complex financing and power purchase agreements that endure for many years. Although the removal of an embedded benefit is a relatively simple implementation, the introduction of a charging mechanism is not. This will require the re-opening of commercial arrangements often across multiple counterparties.

Ofgem have noted that they do not believe that Grandfathering is appropriate because it has signalled the removal of BSUoS embedded benefit in previous years. Whilst we agree with this we do not believe the signal for charging BSUoS was clear. Therefore if Ofgem believe it is for the greater good to charge BSUOS to embedded generation we believe that this should be for new embedded generation only i.e. applying a grandfathering exemption for existing generation.

Furthermore as a general principle, we would encourage a cautious approach when considering applying a charge for BSUoS on to distributed generation (DG), given that typically a large proportion of Balancing Services costs are driven by Transmission connected generation[4]. So while we understand that all costs borne by Transmission connected assets will ultimately be passed on to the consumer, it is rather an implausible stretch for DG to be considered an appropriate target to carry BSUoS costs.

[4] National Grid's response and reserve products are there to manage the risk of Largest Loss of Load (LLoL), and other conventional generation plant falling short of declared MW output or tripping-off altogether – all contributing significantly to BSUoS.

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.

Yes. The remaining embedded benefits are small. We agree that addressing these is not a priority.

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

The remaining Embedded Benefits should be maintained and we consider that Ofgem's current rationale is comprehensive.

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.

a) We are concerned that the almost dismissive statement that there will be a 'winners and losers' is likely to alarm the business community[5]. What this actually means for UK companies is that there could be unnecessary, unwarranted harm to those customers sitting at the lower volume thresholds, potentially damaging their competitiveness and/or resulting in job losses.

   Reform should be introduced through a phased implementation approach, with a substantial notice period after the decision date. We note that for the changes to residual charges, the proposed implementation date is now April 2021, with the potential for phasing across 3 tariff years. While this is a welcome (and absolutely necessary) delay to the original April 2020 originally quoted by Ofgem for the introduction of the changes to residual charges, we would urge Ofgem to delay this date out further – bringing it in line with the introduction of the changes to Forward Looking Charges which are inextricably linked. There should also be a phasing over 3 tariff years. The timescales should align to ensure DNOs continue to provide 15 months' notice of DUoS charges. Derogation not to provide 15 months' notice of DUoS tariffs should not be an option.

b) On charging BSUoS to embedded generators, a sudden "shock" introduction of charges next year does not provide for a predictable and stable environment. Furthermore in practical

[5] This position needs to be considered very carefully as the industry has experience of similar issues when 'simple fixed charges' were applied to DUoS for UMS (public lighting) customers – resulting in unacceptable financial hardship for small lighting customers and significant windfalls for large local authorities and highways agencies. A Charging change that Ofgem and the DNOs were ultimately made to reverse-out.

terms many generators that have exited long term financing arrangements sell into the forward market that is liquid up to 3 years and plan on that basis. The introduction of new arrangements at the end of that forward looking term allows for adjustment in plans and commercial arrangements to facilitate this. We would suggest that timescales are aligned with changes to forward looking charges and are phased over 3 tariff years.

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

Yes, we agree with Ofgem's minded to decision on Residual Charges. The fixed charge option is the most practical approach and can be implemented relatively easily since it uses readily available historical volume data.

We would suggest a single fixed charge for both domestic unrestricted and domestic Economy 7 customers, We see no reason to differentiate between the 2 types of customers.

The Capacity Option is not a viable option for domestic customers and we believe should not be considered further. Not only would it be impractical to implement (the need for costly additional industry data flows and new processes to manage the data), the methodology of deeming domestic, and also small non-domestic capacities, could lead to large swings in tariffs if capacities are over or underestimated.

We have raised in our response **(Questions 4, 7 and 8)** our observation that the segments for half hourly metered business customers can have a wide range of customers. Should Ofgem wish to provide additional segmentation within each fixed charge segment, we believe our fixed : capacity hybrid method (for half hourly metered business customers only) would be a practical way to do this.

We believe that implementation should be aligned to the introduction of the changes to Forward Looking Charges = which are inextricably linked. There should also be a phasing over 3 tariff years. The timescales should align to ensure DNOs continue to provide 15 months' notice of DUoS charges.

We do not agree with Ofgem's minded to decision on the remaining non-locational benefits.

We are concerned that the policy approach to embedded generation is not consistent or holistic. Whilst the consultations on the Smart Export Guarantee encourages embedded and renewable generation other consultations such as this one significantly undermine the business case. We would like to see a review of the strategy for embedded and behind the meter generation rather than a piecemeal approach.

We believe that policy decisions should enable a predictable and stable mechanism to facilitate the development of embedded generation in a manner that supports the transition to a more flexible and low carbon network. The sudden introduction of changes and price shocks to the system should be avoided where possible. April 2020 or April 2021 is an unacceptably short timescale for implementation. We believe that implementation should be aligned to the introduction of the changes to Forward Looking Charges - which are inextricably linked. There should also be a phasing over 3 tariff years.

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.

The fixed charge (preferred option) is the most practical way to implement segmentation within the Industry. The approach is already used for CDCM DUoS charging. It does not require additional data flows across the industry. LLFC is maintained and easily available. The approach uses historical volume data that is readily available. National Grid as SO will require a version of this historical volume data for billing purposes but this should be a relatively easy approach.

The consultation, as it stands, is not clear on how to handle the scenario where DNOs have multiple LLFCs within a distribution tariff. In our answer to question 9, we have clarified how we believe this should be handled i.e. the grouping is not the individual LLFC, the LLFC is used to identify the Distribution Use of System Tariff.

> e.g. Manweb Domestic Unrestricted has LLFCs of 101 and 102 associated to it.To provide clarity, under the fixed charge approach, customers in the Manweb area with LLFCs of 101 and 102 should be grouped under the same Domestic Unrestricted segment i.e. it the grouping is that used for the Distribution Use of System tariff, not individual LLFC. The LLFC is the key field to use to identify the grouping into customer segment and we support using it. This approach for grouping together customers is already used in DUoS tariffs.