Targeted charging review: minded to decision and draft impact assessment

Veolia Response 04 February 2019

About us

Veolia is the UK leader in environmental solutions, providing a comprehensive range of waste, water and energy management services designed to build the circular economy and preserve scarce raw materials.

Our business strategy - ‘Resourcing the World’ - is focused on manufacturing green products and generating low-carbon energy in addition to helping its customers and suppliers reduce their carbon impact. This has resulted in the company receiving the Queen’s Award for Sustainable Development.

In the UK, Veolia employs 15,000 people and has invested £2bn to date in vital infrastructure designed to boost the green economy, from material recovery facilities and reprocessing plants to energy from waste facilities and heat networks to landfill sites.

Veolia is a decentralised energy generator providing sufficient energy to the National Grid to Power 1.2m homes via low carbon Energy From Waste (EFW), Landfill Gas To Energy (LFGTE), Combined Heat & Power (CHP) and Anaerobic Digestion (AD).

This consultation response outlines Veolia’s grave concerns that the Targeted Charging Review (TCR) discriminates against baseload low carbon generators that do not appear to have been included in Ofgem’s modelling and is inconsistent with Government policy.

In essence the nuclear industry, ‘Big 6’ (British Gas, EDF Energy, E.ON, Npower, Scottish Power and SSE) are using ‘code review’ i.e. administrative means under Ofgem to review how decentralised small generators are rewarded for managing lower energy use and Grid flexibility, as well as the embedded benefits they receive for this.

Put simply these embedded benefits are not subsidies, but payments made to small generators connected to local networks to offset Grid costs of reinforcing the network at higher voltage levels.

Veolia disagrees with Ofgem’s view that residuals are “fixed” or sunk costs. Residuals are the top-up created by the network companies’ revenue settlements and the european cap on transmission costs (2.50 EUR/MWh).

Clearly the large companies want to stop the small ones from developing the decentralised Grid, but this is not the smart, flexible, electric vehicle ready, decarbonised, digital future the UK needs.
Ofgem’s preferred option, to move away from consumption-based to fixed charges, means that the most profligate energy users will be rewarded, while those that take action to effectively manage and reduce their electricity consumption are penalised.

This cannot be fair or the right direction for the UK. Under this option the hardest-hit sector will be the thousands of forward-thinking businesses nationwide which invest in storage and on-site generation.

Ofgem's actions are in direct conflict with BEIS Industrial Policy to develop a smart and flexible energy system that takes into account greater low carbon generation. They are anti-competitive, potentially challengeable under Judicial Review and are being undertaken 'under the table' while Ofgem acknowledges consumers cannot properly calculate the new costs they will be expected to bear.

They might save the householder a small initial amount per year, but the much greater risk is an outdated, inflexible Grid, as the decentralised assets are run down, investment stalls and the UK is left only with large bulky assets, exaggerating reliance on the interconnectors to Europe.

This will impact the Government's 25 year Environment Plan as it has a very high impact on solar, AD, EFW, materials recycling and the green sector - potentially costing local authorities hundreds of millions in additional costs as they are passed through or where they deliver direct services.

The Government's Resources & Waste Strategy was designed to support the sector's growth by encouraging investment and e.g. proposes mandatory food waste collections that will require the significant expansion of the AD market. However, Ofgem's proposals could result in existing AD plant being decommissioned by invalidating the current financial model and undermining the investment case for building new low carbon generation across the sector.

The proposals will also impact the UK's competitiveness as light industry is going to be hit hard. The scandal, when it's found out by a wider community, will be big business crushing the UK's decentralised, decarbonised, digital future by imposing a 'one size fits all' solution that will reduce the Grid's overall resilience through discouraging investment in new infrastructure.

Veolia trusts that the evidence it provides will encourage Ofgem to think again about its 'minded to' proposals' and provide the necessary time to evaluate fully the impact on light industrial users, energy from waste plants and anaerobic digestion.

It is hoped our contribution will shape the future of decentralised energy generation and preserve the future of a Grid open to small, low carbon operators, as well as large players.

Veolia responses to the consultation questions:

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

In a world of perfect competition it would make little difference whether demand or generation paid for the residual charge because competition would ensure that generation passed the cost through to consumers. However, demand and generation are not treated equally in the electricity market with many actors facing different signals based on their voltage level of connection (transmission or distribution) or the nature of their market access (supplier volume allocation or central volume allocation). By moving the cost on to final demand users who cannot pass them on further, light to medium sized industry is likely to see large increases in cost (see Q4).

Veolia is also concerned about what constitutes “final demand” as the term is not exhaustively defined in the November 2018 TCR Consultation (hereafter, “the TCR Consultation”). If not clearly defined, there is a risk that embedded exporting generators who do not hold a Generation Licence will be caught in the scope of residual charges which we do not believe is the policy intent. We have prepared a proposal to address this issue below.

Executive Summary

- **Ofgem’s policy intent is to charge residuals on demand not generation**
- **Some distributed generators consume power from Grid for short periods**
- **This power is effectively “works power” and should be excluded from the residual charging base**
- **Veolia proposes a solution that would limit “works power” to 10% of export to Grid over an annual period**

Background

Ofgem’s policy position is that residual network charges should be paid for by demand and not by generation. This is a common-sense approach which goes part of the way towards treating generators equally at all voltage levels. However, it is important that “Final Demand” is defined carefully so that generation activities are not inadvertently caught in the residual charging base. This paper explains the issue in light of some recent work done by Elexon as well as conversations held between Thomas Cahill of Veolia and Dominic Green of Ofgem at the Charging Futures Forum in January 2019. In the last section a proposal is made for a definition of “Final Demand” that could be adopted by the CUSC Workgroup that will be tasked with implementing the TCR proposals in network codes.

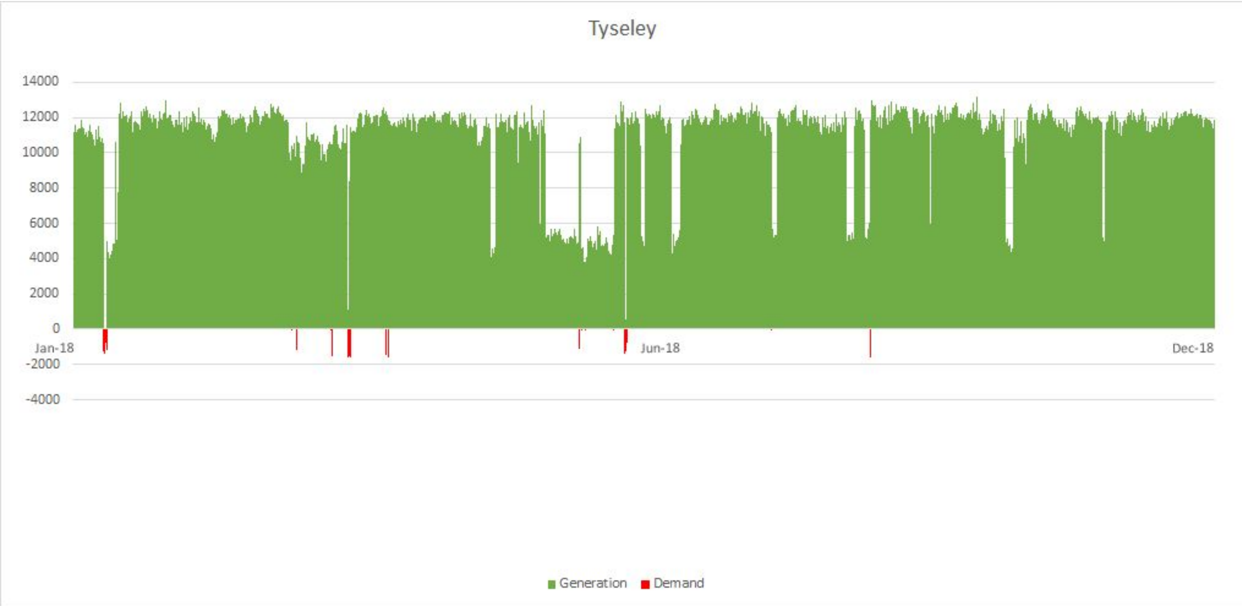
The Issue

Many distributed generators maintain one or more import connections to the distribution Grid for the purposes of startup and shutdown or essential services in the event of a generator failure. This consumption is often referred to as “parasitic load” or “works power”. When:

1. The generator is operating normally, works power is consumed on-site and is netted off export to Grid;

2. The generator is offline, works power is imported from the Grid, registering in a consumption MPAN

Fig. 1, Half-hourly export/import profile for a typical Energy Recovery Facility



The red area in Fig.1 shows periods when the ERF is importing from Grid. Because this is a twin stream station (ie, two boilers) works power is supplied by the turbine when one boiler is off over the summer. When both boilers are off, works power is being used to, amongst other things, maintain waste flow which is an essential part of the environmental permit. Without an environmental permit the site cannot operate. In other words, works power imported from Grid is an essential requirement of power station operations.

Our understanding is that if a licence exempt embedded generator that is not a licenced generator under the Electricity Act (1989) consumes electricity through an import MPAN, all of this consumption is considered to be "final demand" so far as the TCR documents currently stand and will thus be liable for residual charges. Given that most of this consumption is essential for the purposes of generating electricity there is a risk that if the definition of final demand is too broad, it will capture generation activities. This runs contrary to Ofgem's policy intent.

Relevant Literature on the Treatment of Licence Exemptable Generating Plant

Although the subject matter is slightly different, there is a useful parallel with how the consumption in the example above is treated in respect of final consumption levies[1]. This depends on the licence status of the generating station under the Electricity Act (1989). A "Licensable" Generating Plant (as defined in BSC Section K1.2.2[2]) operated by a Licensed Generator would be exempt from final consumption levies whereas "Exemptable" plant operated by a Licensed Generator would not be. Exemptable plant is defined as either <50MW Declared Net Capacity (Exemptable Class A Small Generator) or <100 MW (Exemptable Class C

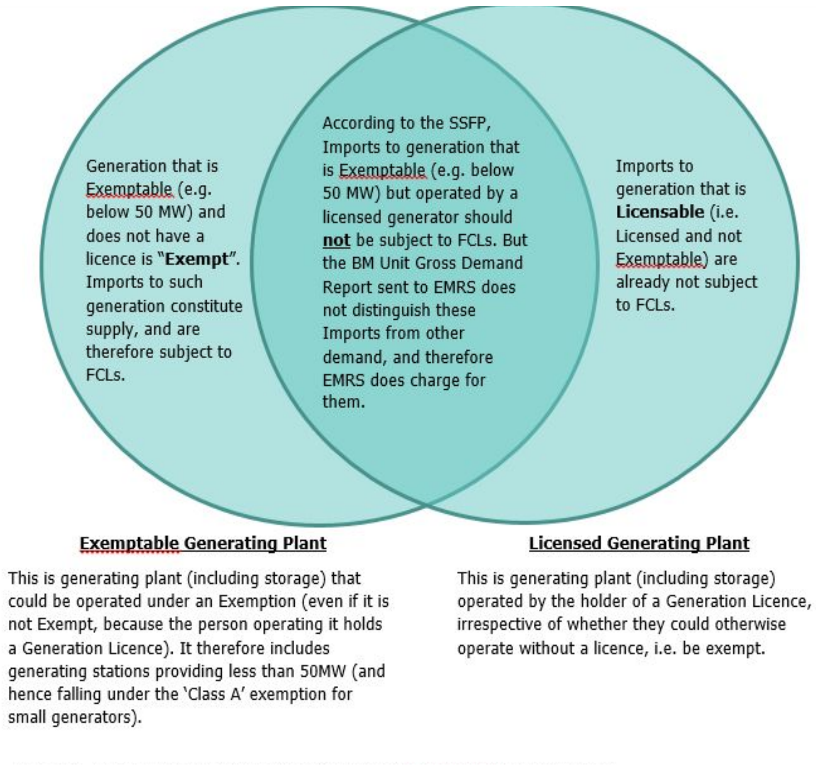
[1] Defined as Renewables Obligation, Contracts for Difference, Feed in Tariffs and Capacity Market Supplier Levy in "Upgrading our energy system: smart systems and flexibility plan" (BEIS/Ofgem, July 2017), p.22 ("Issue 1.3")
[2] "Aligning BSC reporting with EMR Regulations: Elexon Consultation on reporting of Gross Demand Data to EMR" (Elexon, October 2018), p.7

Generator[3]). Elexon provided a Venn Diagram showing the overlap of these class exemptions in their October 2018 consultation[4]:

The principle is the same that licensed generators should not be charged final consumption levies (ie cost recovery that is usually paid for by demand) when electricity is used for the purposes of generation. Similarly, it is our view that the TCR residuals should not be paid by demand meters that supply electricity necessary for the purposes of generation, whether this generation takes place in Exempt, Exemptable or Licensable generating stations.

The BSC Panel agreed in November 2018 that Elexon should work on an interim solution to identify supplies made to licensed generators at Exemptable Generating Plant and rely on self-declaration by licensed suppliers of eligible metering systems. The work undertaken as part of the interim solution could be usefully applied in the delivery of the TCR but the scope should be expanded to include Exemptable Generating Plant operated by persons not holding generation licences as otherwise "final demand" under the TCR will continue to capture embedded generation.

Fig.2, Illustrating that Generating Plant may be Exemptable and Licensed



Veolia Proposal for a Definition of Works Power

In order to avoid consumption used for the purposes of electricity generation being captured in the definition of final demand we propose a simple definition of "works power".

[3] See Article 3(1)(a) and Schedule 2 of The Electricity (Class Exemption from the Requirement for a Licence) Order 2001
[4] Cf (2), p.7

Any electricity supplied from the distribution grid to an Embedded Exemptable Generating Plant where the energy supplied does not exceed 10% of the energy exported to the distribution grid in the period 1st April to 31st March each year.

We propose that works power should be excluded from the scope of final demand for the purposes of residual charging under the TCR. Some practical considerations are presented below.

1. *Assurance*

In reality some of the consumption at the generating station will not be required for the purposes of generating activities. This consumption would normally be netted off export during periods of normal operation however when the plant is importing from Grid it is impossible to distinguish this demand from works power through current Supplier Volume Allocation (SVA) processes. To avoid the need to introduce new processes (although, as discussed above, Elexon is working on new processes to deal with the case of licensed generators and CMP280 will also require change to existing systems anyway), we propose a directors' declaration that all the power consumed is necessary for generation activities. Operators of plant could install new import supplies at HV or LV for non essential services (offices, canteen etc) which would pay their share of fixed residual costs appropriate to their line loss factor class.

The 10% rule should also ensure that consumption during sustained periods of plant outage does attract the TCR residual. By measuring consumption back to back with the network companies' charging year any over or under recovery occurring as a result of a site moving into or out of the scope of the works power rule could be managed smoothly. However, the number of sites concerned is likely to be small as most generators will seek to maximize availability and reduce costly shutdowns.

2. *Mapping import to export meters*

EHV generating sites: DNOs currently have access to meter level detail showing where export and import MPANs are located on the same site (this information is displayed on Use of System Charging Statements as site specific line loss factor codes).

HV generating sites: DNOs do not necessarily have access to the same level of granular detail as at EHV with line loss factor codes being shared by many export and import sites. One solution would be for the directors' declaration proposed above to include a statement that MPAN 'x' is for import and MPAN 'y' is for export. A parallel would be the PP11 Climate Change Levy Supplier Certificate provided to licensed suppliers for the purpose of administering CCL reliefs. On this form, an authorized representative of the company warrants that an MPAN number is located on a particular site.

Assessment of Proposal against TCR Principles

- *Reducing harmful distortions*

Baseload SVA generating stations which export to Grid for most of the year do not engage in "Triad avoidance" because they currently do not face the Triad residual unless they are on shutdown in the period November-February. Such stations currently benefit from the Embedded Export Tariff under CMP 264/265: it would seem absurd to remunerate stations (as generation) for offsetting transmission costs during Triad under this tariff and then charge them (as demand) these costs under the TCR.

- *Fairness*

As stated in paragraph 3.7 of the TCR "Minded to Decision", 'all final demand users who benefit from the electricity network should pay towards it upkeep in a fair manner'. Obtaining a watertight definition of final demand is therefore essential to making sure charging arrangements are fair.

As discussed above, there should be a level playing field for generators regardless of their licensing arrangements under the Electricity Act. At the same time, import consumption which is not for the purposes of generation activities should be liable for residual charges otherwise there would be a perverse incentive to install generation in order to avoid residuals on sites which are predominantly electricity consumers. We suggest that a simple 10% cap on imports from grid would allow generators to be distinguished from consumption MPANs.

- *Proportionality and practical considerations*

See the considerations on 'Assurance' and 'Mapping Import to Export meters', above.

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.

We do not accept the conclusion that a fixed charge meets the test of being fair for all users. Veolia considers the leading option that most fairly allocates cost to be the Agreed Capacity Charge. We understand that this would lead to severe distributional effects at the domestic level if applied to households, however we do not see why a hybrid option of fixed charging at domestic voltages and agreed capacity charges at non domestic voltages could not be implemented. The Agreed Capacity Charge meets the "pay for what you use" criterion which is at the heart of fairness in energy networks. By contrast the fixed charge at non domestic voltages will lead to consumers paying for more than their fair share through the use of line loss factor classes (see answers to Q4, Q5).

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?

No, the current method is fair because users who use more of the network (ie LV) should pay more in residual charges. However, it is noted that this method of cost allocation is somewhat outdated and supposes that power flows from transmission to distribution and from distribution to demand respectively. In reality, flows are increasingly bi-directional and solely local. In future work it is likely Ofgem will have to look at this principle again.

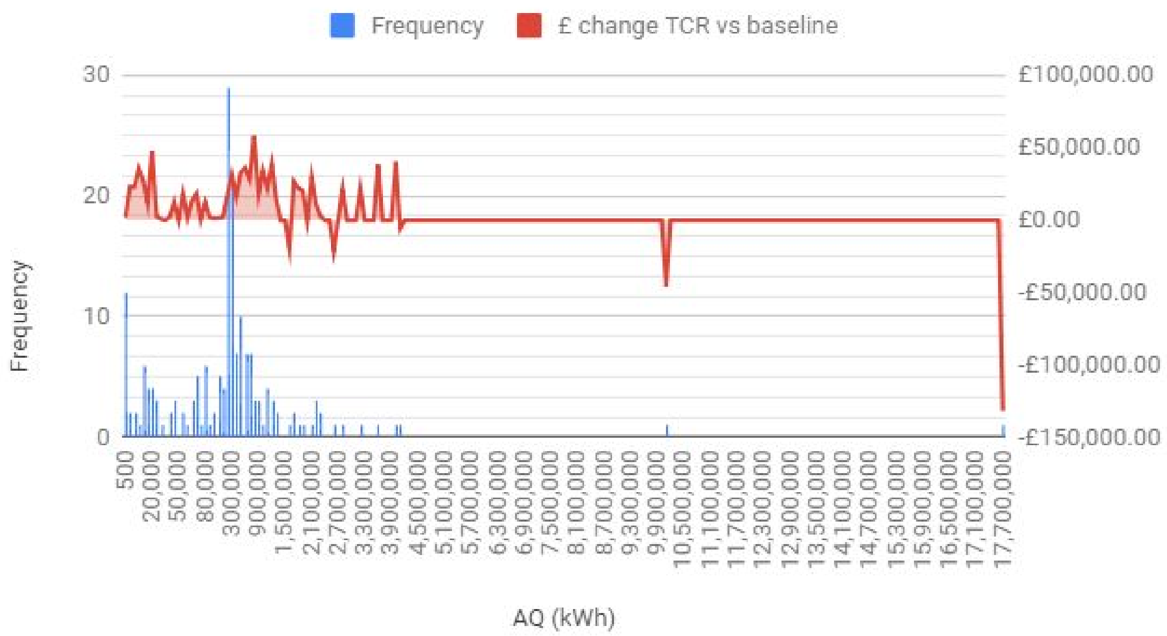
4. As explained in paragraphs 4.41, 4.43, 4.46, 4.49, 4.80, we think we should prioritise equality within charging segments and equity across all segments. Do you agree that it is fair for all users in the same segment to pay the same charge, and the manner in which we have set the segments? If not,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

We see why in the interests of simplicity, line loss factor classes have been used to segment demand. However, we are concerned that this gives rise to considerable distributional impacts on smaller HV users which have not been sufficiently modelled in the Impact Assessment[5]. The assumption in the modelling[6] is that a 'light industrial user' is 'half-hourly metered [and] connects at HV with annual consumption of 5,000 MWh' ('User Group 11, p146 of Impact Assessment'). The LLFC that has been chosen to represent this user group is "HV HH metered". The modelled fixed charges for this LLFC are £17,380 per MPAN for TNUoS residuals[7] and an average of £37,570 for distribution residuals[8] or a combined total of £54,950 per MPAN. (see example below from the Rainham plastics recovery facility):

[5] 'Distributional and Wider System Impacts of Reform to Residual Charges' (Frontier Economics, November 2018)
[6] Ibid, p.146
[7] Ibid, Figure 155, p.163
[8] Inferred from 'Targeted Charging Review: minded to decision and draft impact assessment', Figure 9, p.43 and 'Distributional and Wider System Impacts of Reform to Residual Charges', Figure 155, p163, assuming site is connected at HV (ie residual is CDCM not EDCM).

The problem with this approach is that the LLFC "HV HH metered" is not representative of User Group 11. The LLFC is assigned by the Distribution Network Operator ("DNO") and is not linked to the annual quantity of electricity consumed. Furthermore, unlike the domestic LLFCs, the "HV HH metered" code is not related to consumption profile: many of the meters in this LLFC have an annual gross demand significantly below the reference quantity of 5,000 MWh. An assessment of the costs faced by Veolia's large number of MPANs (184 meters at HV or LV) serving a variety of depots, waste transfer stations and material recovery facilities confirms the conclusion of Figure 6 in the TCR consultation:

Fig. 3, Distribution of annual Veolia demand 2017



184 meter points (98.9%) consume less than 5,000,000 kWh/year, but will see an average increase in charges against the 2017/18 charging year of 192%. Only the very large sites which could otherwise be outlying members of the EHV user group will see savings.

Paragraph 4.42 alludes to the possibility of creating additional bands within LLFCs 'for example to split out smaller and larger users within a band'. We strongly encourage Ofgem to consider further segmentation to avoid the "cliff-edge" effects on users at the extremes of each band.

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)?

As discussed in Q1, Veolia is concerned that plants that export electricity to Grid most of the time rather than providing supplies of electricity 'behind the meter' or via 'private wires' are at risk of being caught in the definition of final demand. This would run contrary to Ofgem's policy intent. In Q1 we make a proposal to avoid this happening.

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

Veolia has the following concerns with the modelling undertaken by Frontier Economics:

1. Light industrial users are assumed to consume a median of 5,000 MWh/year. Our evidence provided in Q4 suggests this is too high, leading to significant "boundary" or "cliff-edge" effects in the choice of charging bands. These have not been allowed for in the analysis of distributional impacts.

2. Industrial users are assumed to have one MPAN per site. This is unrealistic: many users must have two incomers for safety purposes (safe shutdown and startup), local network configurations (DNO requirement) or for legacy reasons. As Ofgem has proposed a per MPAN charge the impact on such industrial customers has been underestimated.

3. The system modelling for behavioural response only assumes that DSR is achieved through behind the meter generation and not "true DSR" (ie load shedding or shifting) or energy storage. Veolia's experience of operating a fledgling DSR business primarily on its own industrial sites (material recovery facilities) is that this activity cannot survive the loss of TNUoS residual payments alongside the Capacity Market suspension.

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

Yes, on the whole an agreed capacity charge or fixed charging is easier to implement that the other options, although the current system of net charging at the meter is already well established so cannot be said to be harder to implement than the leading 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.

Fairness

See answer to Q4. We consider that there are severe "boundary effects" on users caught in line loss factor classes that are a poor match for the user groups they are trying to simulate. Impacts on some smaller users can be as much as 200%. We do not consider this to be either fair or proportionate.

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?

The segmentation of user groups by LLFC is a practical solution, however, as mentioned above it can lead to inequitable outcomes in particular for low consumption HV HH metered users. We propose that Ofgem should consider some refinements to the segmentation by LLFC. Suggestions are provided below:

1. *Hybrid Option*: Introduce some form of consumption or capacity based approach to charging for users within the HV HH group. This could, for example, apportion 60% of the charge to a user based on their group on a fixed basis with the remaining 40% of the charge being implemented on a variable basis based on annual consumption levels.

2. *Additional LLFCs:* DNOs are currently undertaking an assessment of the practicality of increasing the number of line loss factor classes to deal with the increasing number of electric vehicles on the system. We believe that given that this work has already begun, it would not impose great cost on industry to engage further with the DNOs in order to achieve a greater segmentation of users.

3. *Apply a postcode filter:* As discussed in Q6, the impact on multi-MPAN sites has been missed. Using existing industry systems (eg ECOES database) it is possible to map users by postcode area. This could be used to ensure that sites with multiple MPANs only pay one charge per line loss factor class or a charge pro-rated across each MPAN.

4. *Directors' declaration*: As discussed in Q1, licensed suppliers currently process PP10 and PP11 forms for the purposes of administering Climate Change Levy reliefs. In principle, a director could warrant that multiple MPANs exist on site and this information could be processed by the licensed supplier.

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.

No comment.

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

Process

No. Firstly, the fast-tracked proposal to remove the BSUoS embedded benefit is inequitable and presupposes the results of the BSUoS Taskforce. The BSUoS Taskforce is being set up to determine the split between forward looking and residual elements of BSUoS. Removing the embedded benefit and replacing it suggests that BSUoS consists wholly of 'residual' costs. This is in effect prejudging the outcome of the Taskforce.

Secondly, although the removal of the BSUoS embedded benefit has been signalled in Ofgem papers for around 3 years to date, *charging* embedded generation for balancing costs has not. This lacks credibility from the perspective of investors and we believe there is no justification for full BSUoS reform without further damaging investor confidence.

Content

We disagree with the assumption that BSUoS is mostly made up of residual elements that distributed generation does not work to offset. There is a clear difference between the impact of baseload embedded generation, such as EFW and LFGTE, on the total sum of BSUoS costs.

<u>For example</u>: Firstly, embedded generation running at baseload provides a number of benefits to the Grid. Baseload generation, by definition is not responsible for causing imbalances on the Grid. Baseload generation in high demand GSP zones can in fact help to reduce demand on the transmission network. Around ~35% of BSUoS costs consist of 'constraint management' payments, baseload generation works to reduce these costs and should thus not be charged the same costs for balancing as other embedded generators.

There are in addition a number of other cost components of BSUoS which baseload generation can help to reduce. Baseload generation tends to export during times of high demand, this reduces the level of reserve payments that must be made to transmission connected generators, another significant component of BSUoS.

Finally, the synchronous nature of many embedded generators provide a greater inertia to the Grid thus helping to manage frequency fluctuations lessening the need for balancing services. It would be logical to wait for the results of the BSUoS taskforce before implementing any drastic reforms to embedded generation which may have to be removed after a few years. This would be consistent with the transparency and predictability components of the fairness principle of the TCR.

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? Please state your reasoning and provide evidence to support your answer.

Yes, but we note the statement in 6.8 that the other embedded benefits are "low in value and hence unlikely to be causing major distortions". In our view, the distortion caused by the transmission and distribution residuals is due to their magnitude and not to the fact that embedded generation or behind the meter generation can access these payments as revenue streams. This is why our preference is for the forward looking and residual work to be aligned rather than looking at the latter in isolation before adjusting the former at a later date.

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

No comment.

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) *Residuals*

We favour a phased introduction of changes to residual charging at transmission and distribution over 2021-2032. As discussed in Q6 we think that the distributional impacts of a move to fixed charges have not been sufficiently modelled: it is therefore too soon to commit to an April 2021 timeline as further work must be done on segmentation of line loss factor classes. We also acknowledge Ofgem's decision to phase implementation of the Embedded Export Tariff under Code Modification Proposal CMP264/265 and see this as a precedent for the industry.

b) *BSUoS*

We disagree with the proposed changes to the BSUoS charges for the following reasons:

Firstly, as discussed above, the BSUoS Task Force should be given time to conclude (ideally over 12 rather than 4 months) which elements of the charge are residual before the embedded benefit is removed. Therefore, we would argue that this change should take place in April 2021 at the earliest.

Secondly, full BSUoS reform is not justified - in effect those contributing to 'balancing' the Grid are being asked to pay for the privilege.

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

In summary, Veolia considers the leading option that most fairly allocates cost to be the Agreed Capacity Charge. We understand that this would lead to severe distributional effects at the domestic level if applied to households, however we do not see why a hybrid option of fixed charging at domestic voltages and agreed capacity charges at non domestic voltages could not be implemented. The Agreed Capacity Charge meets the "pay for what you use" criterion which is at the heart of fairness in energy networks. By contrast the fixed charge at non domestic voltages will lead to consumers paying for more than their fair share through the use of line loss factor classes.

As discussed in Q11, we do not support Full Implementation of BSUoS reform as this is effectively a prejudgment of the conclusions of the BSUoS Task Force. We also consider that Ofgem has not sent sufficient signals to the market that BSUoS would be imposed as a charge on embedded generators and therefore do not think this change should not take place.

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.

As discussed in Q9, multi-MPAN sites are not mentioned once in either the TCR document or Impact Assessment.