ofgem

Memo

Charging design—Options listing

Final version

From	Ofgem (Andrew Conway, Scott Sandles)
To	Challenge Group and Delivery Group
cc	
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1. Introduction

1.1. This document is on charging design which is about the structure of the network charge. Charging design involves choices such as between volumetric or capacity (or alternative) charges, whether charges should include seasonal differences, and whether the same charging design should be faced by transmission and distribution users and between generation and demand users. Questions of the locational granularity of the charge are being addressed in a separate but complimentary work-stream. Any of the charging designs in this document could have charges which differ by location.

1.2. The scope of Ofgem's Significant Code Review (SCR) into electricity network access rights and forward-looking charges includes:

- A wide-ranging review of distribution network use-of-system (DUoS) charges; and
- A focused review of transmission network use-of-system (TNUoS) charges.

1.3. In launching the review, we have not at this stage "ruled-in or out" any specific charging design for:

- DUoS charges on demand users;
- DUoS charges on generation users; or
- TNUoS charges on demand users.

1.4. The purpose of this document is to finalise the charging design options we should assess for these users. We have set out a potential list of options in this document for consideration. We have grouped these options into generic (or "basic") options and variants of those options (variants of the basic options are presented in appendix 2). We have also grouped the options between those applying to demand users and those applying to generation users, with more focus on the charging design for demand users, at this stage.

1.5. In appendix 1 to this document, we also include a discussion of charge designs used internationally. The international case studies have influenced the development of our list of potential charging options, and also provide more context to understand the implementation of different charge designs.

1.6. In appendix 3, we summarise the current charge design for DUoS and TNUoS users.

1.7. This document **does not:**

- Assess any of these options – Our starting point is simply to list the options for assessment. Though in the last question above we are asking Delivery Group members to nominate one option which they consider has the least potential.

- List every possible variant of the basic options, of which there would be a limitless number. Instead, we have attempted to list a maximum of 5 distinct variants for each basic option which broadly covers the field of possible variations.

- Discuss how blended options (such as capacity based and volumetric) options could be implemented as variations. Blending options will be considered later in the project.

- List variations which are specifically intended for consumer protection reasons – Our focus at this point is on the economic efficiency and practicality principles outlined in the SCR launch statement. Refinements to these variations for small users for consumer protection reasons will feature in a later part of the assessment, after an initial shortlisting of these charging design options.

- List options which involve both charging and access right components – Our focus at this point is on listing charging options (and separately listing access right options through a different work-stream). Turning these into combined charging and access right options will feature in a later part of the assessment, after an initial shortlisting of these charging design options.

- List options for non-half hour (NHH) settled customers – Our focus at this point is on customers who have a smart meter and are half hour settled.

- List options for TNUoS charges on generation users – In the scope of the SCR, we did not propose to review TNUoS charges on transmission-connected generation users.1 Instead, the SCR proposed a review of whether the current TNUoS charging design for transmission connected users should also be applied to small and larger distributed generation (DG) users.2

- Consider how the charging structure may be reflected in retail tariffs. Currently, suppliers are the intermediaries in the system who are charged network charges by the network companies. End users are not charged network charges directly. Suppliers can either pass-through network charge structures to customers, take some of the risk by socialising charges or implement technology solutions - the Future Retail Market Design project is considering reforms in this area, and so is out of scope of this project, but we will be considering how potential changes to the retail market should influence our choice of network charging design.

- Consider how the non-peak demand/congestion cost drivers should be reflected in the charge design. Non-peak demand/congestion cost drivers may include reactive power, fault levels, volumes, and number of customers. These issues are currently being considered in the network cost driver sub-group and will be considered as a component of the blended options.

[1] The exception to this is that reviewing the Reference Node used in the Transport Model, which is within scope of the SCR. Changes to the Reference Node has the potential to effect the TNUoS charges for all users, including transmission-connected generation users.
[2] Larger DG users currently face the same wider locational TNUoS charges as transmission-connected generation users, but do not face the local charges. Small DG do not currently face either of these sets of TNUoS generation charges, and are instead treated as "negative demand".

2. Feedback from the challenge group and delivery group

2.1. The original version of this note was shared with the challenge group and delivery group. Each group had the opportunity to provide feedback at the most recent workshops and through an online survey. The survey questions were:

- Have we identified all the basic options for demand charging?
- Are there specific variants for demand charging that should be added?
- Have we identified all the basic options for generation charging?
- Are there any other comments you would like to add?

2.2. A small number of respondents have answered the survey, and many of the respondents agreed we had covered the main options for charging. In both the survey and the workshops, there was some useful feedback which we have for the most part integrated into our options listing. These points are summarised below.

- There is a question about whether forward looking charges should send investment or operational signals. A number of participants argued that charging signals that change annually and aren't locked in for years in advance send very weak investment signals, particularly if they are volatile. One participant suggested that charging signals could be fixed for a number of years ahead to send stronger investment signals. However, this would clearly reduce the ability to send strong operational signals, and may impact cost-recovery. This is an important question. Our view is that charges should potentially send both investment and operational signals. While we do not express the option described above, we will consider the implication of the issue when we assess the consumer response to different options.
- An additional variant was identified which was described as a hybrid of volumetric and capacity charging. Users would have an agreed kWh usage per day/month/year, paid as a subscription, with surcharges if exceeded. This could even be profiled within day and could be useful for networks to forecast need. We have added this option as a variant of the volumetric time of use charges.
- One survey respondent suggested that a demand charging variant could be based on the statistical difference of the user's load profile as compared to the aggregated load profile of other users connected to the same GSP. We have decided not to include this in the assessment. While this option may have merit, we have found no evidence of this approach being used for charging, and considering the complexity and novelty of the option, we have ruled it out before taking it forward for assessment.
- A number of participants highlighted that we need to consider how onsite generation, storage and shared access rights are treated within the options as we developed more detailed options for the generation charging. We have now included discussion in the generation charging sections about options for treating these.
- A number of participants suggested that generation fault levels will need to be considered in the forward looking charge design. As this document describes options for reflecting the costs of peak demand, we have decided not to include this within the options. However, we have highlighted this to the cost drivers' sub-group, which will consider this alongside other non-peak cost drivers.

- One participant suggested that we need to consider how planning standards will influence the design of the charging options. The impact of planning standards on charge design options will come through both the network cost driver piece (leading to the cost reflectivity assessment of the options) and when we package the charge design options with access options.

- One respondent suggested an additional generation charging option based on historic load factors. The methodology is to set a forward looking charge based on the networks' marginal reinforcement cost in the form of a capacity charge, moderated by the average historic load factor. This option was developed during project Transmit to be applied to transmission connected generation. We have included this option as a basic generation charging option.

- One participant suggested that generation charges might be more granular on a locational level than demand, in similar way to how TNUoS charges are currently treated (where there are more TNUoS generation zones than TNUoS demand zones). The reason for this would be that generation users are generally more engaged with energy and network costs and so it may be more appropriate to expose them to a greater level of cost-reflectivity. We have included this discussion within the basic generation option 2.

- One participant suggested that the document should be restructured to bring out dynamic pricing options more clearly. We have widened the definition of the critical peak pricing basic option to include dynamic ToU and renamed it as 'dynamic charging.

- One participant suggested that the volumetric ToU time bands could be set on the basis of the Electricity Forward Agreements, which are a standard trading block used on power exchanges. We have included this as a variant in the volumetric ToU section.

3. Summary of basic options

3.1. In this document, we have developed options for individual HH settled users, supplier aggregated options and options for generation users (see table 1). For individual HH settled users, these would be options where the suppliers are charged by the networks based on their customers' individual characteristics,[3] and suppliers can choose how to charge their customers. Supplier aggregate options are ones where the DNOs or ESO charge the supplier based on the aggregation of their customers' characteristics, and the supplier chooses how to charge its customers. Supplier aggregate charging options largely follow similar options for individual HH settled users, though we believe some options may not scale well, and so have not listed them.

3.2. Option developed for generators are slightly different in that they consider how the demand charges are treated for generators. We present options for generators as a set of questions of how to reflect the demand charge design.

3.3. The basic options we have identified are:

- Basic option 1: Volumetric ToU – whereby users are charged in £/kWh, at different rates during different time bands.

[3] Currently, the electricity supplier faces network charges associated with the consumers they supply. The supplier decides how to respond to these signals, including how to reflect them in the tariffs and packages they offer their customers (eg they may offer ToU tariffs or technology to support flexibility).

- Basic option 2: Actual capacity – whereby users are charged on the basis of their actual maximum capacity, in £/kW.

- Basic option 3: Agreed capacity – whereby users agree a capacity limit ahead of time (or suppliers agree this on behalf of their customers), and pay a £/kW charge for the capacity.

- Basic option 4: Dynamic charging – whereby users are charged high prices during periods of actual network congestion, and very low prices the rest of the year. Examples of this include critical peak pricing and dynamic ToU.

- Basic option 5: Peak rebates – whereby users are paid to reduce demand during times of actual network congestion.

Table 1: Basic options for users

	Individual HH settled demand	**Supplier aggregated**
Volumetric time of use	✓	✓
Actual capacity	✓	✓
Agreed capacity	✓	Unclear
Dynamic charging	✓	✓
Critical peak rebate	✓	**x**

3.4. Questions of how to reflect the charge design for generators (described in greater detail in section 6):

- Should generation face the same basic charging options as demand?

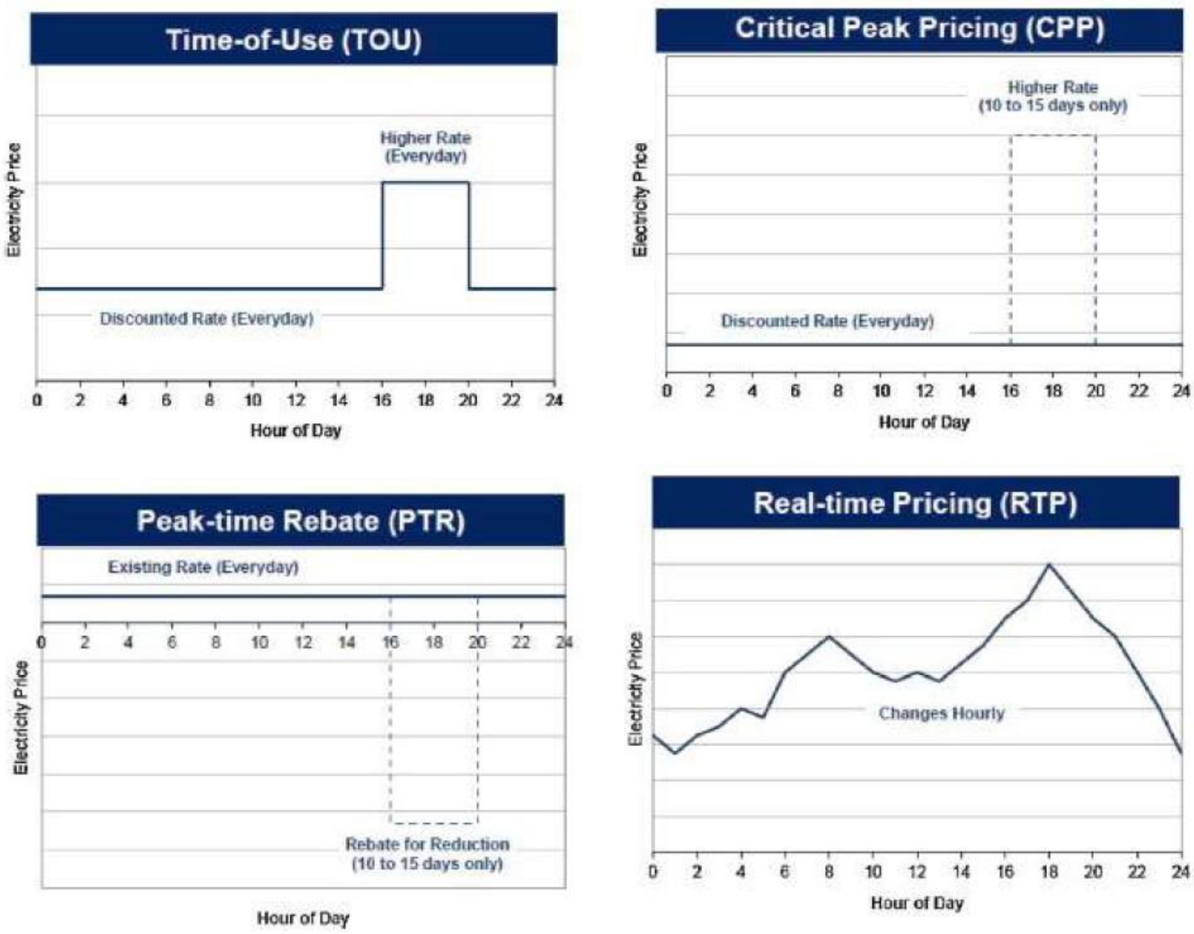
- Does generation only receive credits or receive credits and charges?

- Are generation charges more or less granular than demand charges?

- Is a load factor adjustment made to the charge for generation? Should different types of generation have different adjustments (eg. TNUoS different treatment of conventional low carbon, conventional carbon, intermittent)?

3.5. How should onsite generation, storage and shared access be treated? Does it depend on whether it is importing or exporting?*Figure **1*** shows a stylised comparison of the volumetric ToU, critical peak pricing, critical peak rebate (called 'peak-time rebate' in the figure) and dynamic ToU (which we consider as a variant to the dynamic charging basic option, called 'real time pricing' in the figure) options.

Figure 1: Comparison of how some charge designs work



Source: Brattle Group, 2018

3.6. Many of the options we have developed rely upon the use of HH settled data of individual customers. Currently, these options would not be viable for domestic users as discussed above. Therefore, we include some variants where HH settled data for individual users isn't used, particularly where we present variants based on current arrangements. However, we believe that the use of HH consumption data of domestic users will be required to realise many of the benefits of charging reform.[4]

3.7. In addition to the variations to the basic options outlined below, there are a number of cross-cutting variants. These include different options for methodology setting the time bands for peak, shoulder and off-peak period – for example

- There could be a common codified methodology
- Networks could be provided the flexibility to determine their own methodology but require Ofgem approval, or
- Networks could be provided the flexibility to determine their own methodology and not require Ofgem approval.

3.8. Even if the methodology is network determined, there might be limitations specified in the codes – e.g. can different time bands apply for different users? For capacity

[4] Use of the domestic data is currently under review under our Half Hourly Settlement SCR.

charges, are the charges based on instantaneous demand, or the average demand over a HH period? These variants are at the next level of detail, which will be considered later in the project.

4. Charging design for demand users – Options based on individual user circumstances

4.1. The charging design options in this section are options for demand users, which are based on individual user circumstances. In the next section, we list options for demand users, which are based on aggregated circumstances across many users for each supplier.

4.2. The demand user charging options in this section are ones that could potentially be applied for either TNUoS charges or DUoS charges.

Basic option 1: Volumetric time-of-use

4.3. ToU network charges have been widely implemented to signal to users to shift consumption away from standardised peak times. Users are charged a price for units of energy consumed (in £/kWh), and the price varies by time. Generally, times are set based on historic consumption patterns of demand, acting as a proxy for network congestion. Time bands, usually set for a period of a few hours or wider, are defined as peak and off-peak, sometimes also with intermediary (shoulder) periods in between. Seasonal elements may also apply.

4.4. Volumetric ToU charges could also be applied as a limit over a specified period of time. The user would agree to a limit (e.g. a number of kWh per day or month), either through negotiation or from a menu, with an associated price. There would be penalties for exceeding the agreed limit.

4.5. Currently in the UK, access to HH consumption data for domestic users with smart meters is not automatically permitted, though users can opt-in to HH settlement.[5] If consent has not been obtained from the consumer, ToU charges are calculated on the basis of an assumed demand profile. This means that users won't have any financial incentives to shift load from peak to off-peak periods.

4.6. In appendix 1, we provide international examples of ToU volumetric charging options which are used or proposed in New Zealand, Norway, Sweden, Ireland, France, Portugal, Spain and Italy. In appendix 2, we present several variants of this basic option.

Basic option 2: Actual capacity based charging

4.7. Charging users for actual capacity is based on the assumption that network assets are sized to accommodate peak capacity, not total energy consumed. Capacity charges are used in GB (and are a significant element of charging at higher voltage networks) and have been implemented in a number of countries.

4.8. An important aspect of actual capacity charging is whether the charges applied are within pre-defined time periods, so-called ToU actual capacity charging. For example,

[5] Certain suppliers are beginning to offer ToU tariffs and consumers can opt in to share their HH consumption data for this purpose. However, there is no automatic requirement for domestic consumers to take a ToU tariff. It is also not mandatory for a domestic consumer to accept a smart meter in the first place. Data more detailed than monthly is only able to be collected if the consumer has given consent, or if it is necessary for a party to fulfil a regulated purpose. See BEIS Smart Meter Data Access and Privacy Framework, paragraph 2.8, link here.

an actual capacity charge with higher rates during winter peaks would be a ToU charge.

4.9. In appendix 1, we provide international examples of actual capacity charging options which are used or proposed in Australia, New Zealand, Norway and Sweden. In appendix 2, we present several variants of this basic option.

Basic option 3: Agreed capacity based charging

4.10. As with actual capacity charging, the assumption underpinning agreed capacity charging is that capacity drives network costs. However, by agreeing the capacity limits ahead of time, users have greater clarity on bills, and network companies theoretically have more information for reliable network planning. Agreed capacity charges have been implemented now in a growing number of countries.

4.11. There are a number of ways by which agreed capacity charges may vary. The most important distinction is whether the agreed capacity only limits capacity during pre-determined time periods (such as winter evenings), or if it applies all year round. Another important variation is the impact of breaching the agreed capacity limit. In some countries, breaching the capacity limit results in a loss of power (e.g. implemented through limits on fuse size; or the user's capacity is curtailed down to the agreed level), however, surcharges could apply, or users could be 'bumped up' to higher capacity options.

4.12. In appendix 1, we provide international examples of agreed capacity charging options which are used or proposed in Australia, Norway, Sweden, France, the Netherlands, Luxembourg and Italy. In appendix 2, we present several variants of this basic option.

Basic option 4: Dynamic Charging

4.13. In the dynamic charging option, we include charge design options in which either the times or prices are dynamically determined on the basis of actual network conditions. The two main options for this are critical peak pricing and real time pricing.

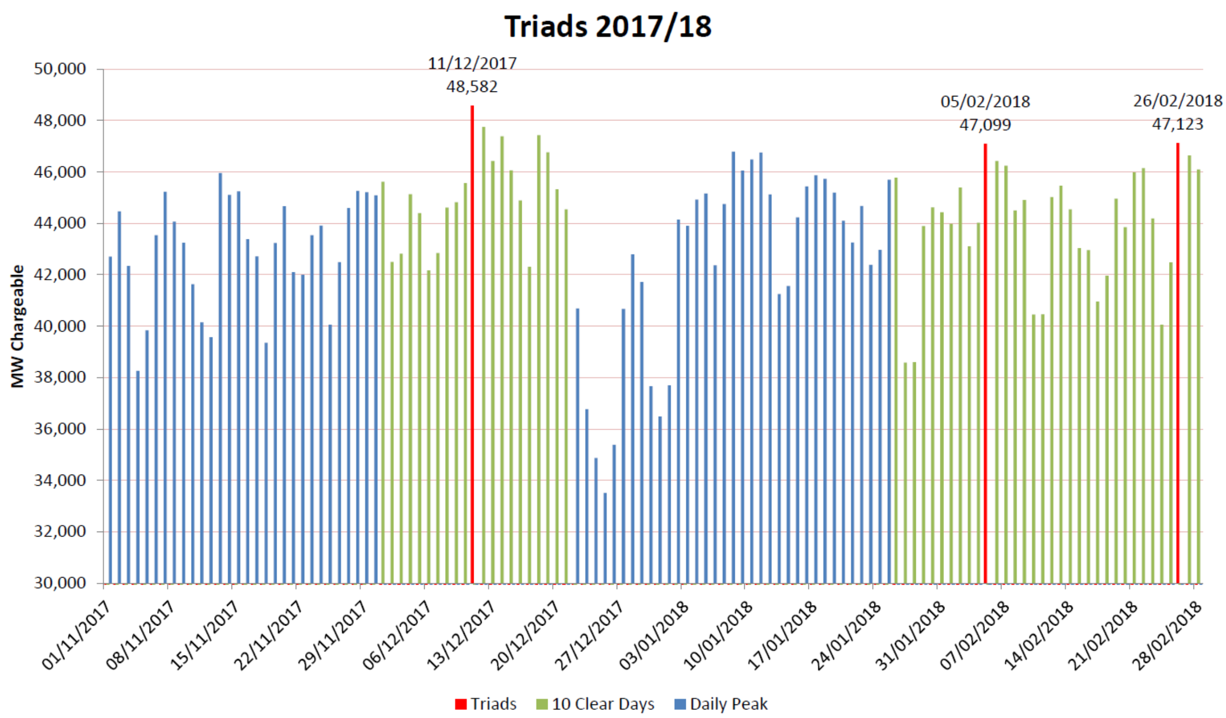
4.14. Critical peak pricing is a charging methodology which charges users a high price for using the network at times of system (or local) peak demand or congestion for a limited number of times in a year (similar to surge pricing implemented by Uber). The assumption underlying this approach is that network costs are primarily driven by periods of extreme system stress (peak demand and/or network congestion), so it is therefore cost reflective to charge users very high rates for use of the system during these small number of extreme times, and to charge users very low or no forward-looking network charges for use of the system during all other times.

4.15. Critical peak pricing has a lot of theoretical support in the literature as a highly cost reflective charging structure, however, it has rarely been implemented in practice. One crude example of critical peak pricing is the Triad charging methodology applied in GB for demand users for transmission charges (see below), which charges transmission users based on the three system peak HH periods (the "triads") in the winter months (that are separated by at least 10 days – see *Figure **2***). However, the way the current Triad methodology is implemented is not the only approach, and there are other variations which could improve on the current approach.

4.16. In recent years, there has been discussion in the literature of real time pricing, which would give a different price for each hour or half hour period. The price would be based on the short run marginal cost and reflect live network conditions.

4.17. In appendix 1, we provide an international example of a critical peak pricing charging option which is proposed in New Zealand. In appendix 2, we present several variants of this basic option.

Figure 2: Peak half hours for Triad charges in 2017/18



Source: National Grid, 2019

Basic option 5: Critical peak rebates

4.18. Critical peak rebates are sometimes referred to in the literature as the inverse of a critical peak price. Rebates are paid to users to reduce their demand during times of network congestion, as opposed to exposing users to high prices during these times. The method draws on behavioural economic principles in order to elicit a greater response than standard critical peak pricing. The method may also be more acceptable for users than the alternative of facing higher charges during high demand periods.

4.19. With critical peak rebates, there is still the need to set an underlying charge design methodology which recovers the costs allocated to the user. This could be a flat or ToU volumetric charge, or an agreed capacity charge. An actual capacity charge is less sensible, given the times when charging for actual capacity would be rational would also coincide with the critical peak rebate charges.

4.20. One of the challenges with the option is that it requires a baseline demand to be calculated for the user, based on historic, agreed or deemed demand profiles, in order to calculate the amount of demand response a user should be paid for. This can be difficult and is potentially open to gaming.

4.21. The use of rebates would need to be signalled to users ahead of time and based on forecasted network conditions, unlike with critical peak pricing which could be implemented ex-post.

4.22. In appendix 1, we provide an international example of a critical peak rebate option which was trialled in Australia. In appendix 2, we present several variants of this basic option.

5. Charging design for demand users – Options based on supplier aggregates

5.1. The charging design options in this section are options for demand users based on aggregated consumption across many users for each supplier.

5.2. The demand user charging options in this section are ones which could potentially be applied for either TNUoS charges or DUoS charges.

5.3. The supplier aggregate options reflect the individual user options above, however, we believe that some of the individual user options (agreed capacity and critical peak rebate) don't scale to the supplier aggregate options.

Basic option 1: Volumetric time of use

5.4. As described in the individual user section, volumetric ToU charges apply differing prices at different times of the day or year, based on a historic understanding of the times of system peak demand. For aggregate supplier options, suppliers would be charges on the basis of their customers' consumption during the different time bands. In appendix 2, we present several variants of this basic option.

Basic option 2: Actual capacity charging

5.5. The actual capacity charge for supplier aggregate would be based on the peak demand of the aggregation of all of the supplier's customers in a region, charged on a £/kW basis. The options broadly reflect how the options would work for individual users, but scaled up to the supplier level. In appendix 2, we present several variants of this basic option.

Basic option 3: Dynamic pricing

5.6. As above, dynamic pricing can be applied at the supplier aggregate level, and works in much the same way. The advantage of applying it to the supplier is that suppliers have more options for responding (such as contracted DSR or grid-scale storage) than individual users do, and so are more likely to be able to respond to dynamic pricing signals. In appendix 2, we present several variants of this basic option.

6. Charging design for generation users

6.1. In this section, we have identified a number of separate questions we need to answer in order to reflect the demand charge design for generators.

Should generation face the same basic charging options as demand?

6.2. The logic here is that the charge design should be neutral with respect to generation and demand, and that responses due to prices (such as demand reduction or increasing generation) should be incentivised in the same way.

Does generation only receive credits or receive credits and charges?

6.3. Importantly, treating generation as “negative demand” and always paying generation a credit (but no charges) makes the assumption that generation always acts to offset demand and reduces network costs in each location. In our SCR launch statement, we questioned the validity of this assumption, due to evidence of constraints being driven by generation, rather than demand.

6.4. The difference is the addition that localised zones or certain times could be designated as either demand dominated or generation dominated zones/times. In demand dominated zones/times, demand users would be charged and generation would receive credits. In generation dominated zones/times, generators would pay a charge, while demand users would receive credits. The designation could vary over time i.e. one region could be a generation dominated zone in the summer due to high penetration of solar PV, but a demand dominated zone in the winter.

6.5. The assumption here is that generation can be either increasing or reducing network costs depending on the location and time of that generation output.

Are generation charges more or less granular than demand charges?

6.6. A variant could include a greater degree of locational granularity for generation users as opposed to demand users, as effectively currently happens for TNUoS charging, where there are more generation zones than demand zones.

Is a load factor adjustment made to the charge for generation? Should different types of generation have different adjustments (eg. TNUoS different treatment of conventional low carbon, conventional carbon, intermittent)?

6.7. In project Transmit, there was a generation charging methodology proposed which would include a load factor adjustment for the calculation of the charge. The basic methodology is to set a forward looking charge based on networks marginal reinforcement cost in the form of a capacity charge. The charge is then moderated by average historic load factor, and the generator is given a credit. The purpose of this option is to link the capacity of a generator to a proxy for the probability that the generator will be operating at a time that will help reduce the need for investment. This could also be applied in generation dominated areas (i.e. where the generator would pay a charge).

How should onsite generation, storage and shared access be treated? Does it depend on whether it is importing or exporting?

6.8. In addition to choosing how the charge design is applied to generators, we also need to consider how to treat onsite generation, storage and local access.

6.9. The issue of treating onsite generation and storage occurs if generation and demand and not treated completely as opposites, which would create the potential for regulatory arbitrage. This could lead to a distortion in investment and operational signals.

6.10. The options for treating onsite generation are:

- Always treat as demand.
- Always treat as generation.

- Treat as demand when the user's demand net of onsite generation is importing, and generation when exporting.

6.11. For users which have shared access (for example, a local community energy scheme with a generator with a PPA to supply a community centre), the scheme could be charged on the basis of its access right. This issue we will explore further when we bring together the consideration of access and charge design.

Appendix 1 – Summary of international examples

1.1 In this annex, we outline our understanding of some cost-reflective charging structures which are being considered or adopted in other countries, with a focus on arrangements for small users (households and / or small businesses).

1.2 The issues being examined by our Access and Forward Looking Charges Reform project and by the Targeted Charging Review are recognised in academic thinking (eg from Leonardo Meeus and the Florence School of Regulation, and the MIT Utility of the Future study). Our findings below are based on a high level review of readily available literature and through discussions with other regulators in CEER[6] and internationally. We will continue to build our understanding and consider these arrangements further in taking forward the review.

1.3 In this appendix, we refer to tariffs which include approaches to both retail tariffs and network charging.

1.4 Broadly, the arrangements include -

- volumetric charges (a price per kWh). These can apply to all usage equally (broadly as per our arrangements for small users now) or vary by time-of-use. Under time-of-use arrangements, the peak/off-peak rates may differ by month of the year, day of the week, or time of the day. They may also vary by location. They may be static (with fixed charges and time bands) or dynamic (where prices can change at different times)

- capacity-based charges (capacity can be defined in different ways with a common approach being a price per kW). These may be set based on an expected maximum capacity requirement (i.e. an agreed capacity) – with either a physical limit on usage or different charges applying above that level - or based on maximum measured capacity over a given period (i.e. maximum demand). They may also vary by location.

1.5 In summary, there has been a move away from standard volumetric charges to more cost-reflective structures. Time-of-use volumetric charges appear to be the prevalent form of cost reflective network charging applied to households, although we have begun to see a move towards a larger proportion of capacity charges in recent years (eg in the Netherlands).

1.6 In the EU, almost 60% of countries have a time-of-use element for households. Capacity charges have been less common - just 40% of EU countries having capacity-based charges for households based on a 2015 study.7 Within English-speaking countries, time-of-use charging is also more common than capacity based charging.8

1.7 Several countries which have a capacity basis for charging have a physical limit (eg a fuse) which corresponds to the capacity basis for their charges (eg Italy, Sweden), while others rely on surcharges when users exceed their capacity level – as in Australia.

1.8 Some of this is driven by very different norms that have been established in countries over time. In countries like Italy (and also France) it seems that fuse size has been set low as a way of protecting the wider network, with consumers accustomed to their

[6] Most recently see https://www.ceer.eu/_network_tariffs_workshop;
[7] Proportions based on Mercados survey of EU regulators published in 2015, reporting data on 21 EU countries, available here: https://ec.europa.eu/energy/sites/ener/files/documents/20150313%20Tariff%20report%20fina_revREF-E.PDF
[8] 'Electricity Distribution Network Tariffs – Principles and analysis of options', the Brattle Group, 2018, available here: http://files.brattle.com/files/14255_electricity_distribution_network_tariffs_-_the_brattle_group.pdf

fuse tripping if they run too many appliances at a given time. This is a significant contrast to the approach taken in GB, where fuse sizes are generally much higher (from 18-23kW). DNOs see their purpose as providing protection to stop the wires into individual households from overloading, and have relied on diversity in demand to protect their wider networks.

Table 2: International examples of different charging designs

Country	Description of charging design
Australia	Historically, the most common form of capacity charge for small users was an ex post capacity charge based on the highest 30 minutes' demand at peak. Concerns from the regulator are leading distributors to rethink this approach. From 2019, charges will be cost-reflective by default for all new connections and customers who change their connection (eg install rooftop solar), or receive a smart meter. Distributors can choose whether to apply time-of-use or capacity charges as default. Time bands are being improved, including to reflect seasonal congestion.[9] Several distributors plan to introduce ex ante capacity charges, currently being trialled, labelled "Lifestyle Tariffs". These have different rates for different capacity bands, and users (via suppliers) choose which best meets their circumstances. These capacity limits are contractual, rather than physical - if actual usage exceeds the chosen capacity, users may face a surcharge or be upgraded to the next band.[10] Approaches have tended to protect consumers through other measures, eg ensuring cost-reflective tariffs only apply to those able to respond, rather than setting explicit minimum levels. Enduring arrangements are still developing. On Australian DNO (Endeavour Energy) trailed a critical peak rebate with consumers over two summer periods in 2013/13 and 2013/14. The trail found participants were able to reduce peak consumption by about 17% during the summer peak period, and found that the participants were satisfied with the program[11].
New Zealand	The New Zealand Electricity Authority is facilitating an industry-led review of distribution network charging. The Electricity Authority has set out guiding principles for distributors to follow in designing their own reforms, proposed to undertake an annual review of distributors progress (assigning star-ratings to each distributor), and set out charging structures it considers are more efficient. It has indicated it will consider any combination of a fixed charge plus seasonal time-of-use volumetric, maximum capacity or critical peak pricing to be more cost-reflective than current arrangements. The Electricity Authority considers seasonal time-of-use volumetric charges are a step in the right direction, but not the end point. It considers critical peak pricing is the best method for pricing congestion and losses associated with the use of the network. Further, its preference is for kVA-based charges, rather than kW charging, as it

[9] Australian Energy Regulator, *Draft decision—Ausgrid distribution determination 2019 to 2024—Attachment 18—Tariff structure statement*, November 2018, pp.60-81 . Available at: https://www.aer.gov.au/system/files/AER%20-%20Ausgrid%202019-24%20-%20Draft%20decision%20-%20Attachment%2018%20-%20Tariff%20structure%20statement%20-%20November%202018.pdf
[10] Ergon Energy, *Annual pricing proposal—Distribution services for the 1 July 2018 to 30 June 2019 period*, pp.56-58. Available at: https://www.aer.gov.au/system/files/Ergon%20E%20Pricing-Proposal-2018-19-V2.0_AER-approved.pdf
[11] Endeavour Energy, *Tariff structure statement*, November 2015, pp. 47-49, available at: https://www.aer.gov.au/system/files/Endeavour%20Energy%20-%20TSS%20-%20November%202015.pdf

	considers kVA is more analogous to congestion and can signal both active and reactive power use.[12]
Norway	Current regulation gives DSOs a large degree of freedom in how they design tariffs. For households, vacation homes and small commercial customers, tariffs mainly consist of a fixed charge and a volumetric charge. Customers with an installed capacity exceeding a set limit, or an expected consumption threshold, usually also have a capacity charge, based on capacity used within defined time bands. A recent consultation envisaged a greater shift towards capacity charges for customers at 22 kV or lower, with a preference for charges based on installed capacity, at least initially. However, the regulator recognised that volumetric ToU charges may be more intuitive for households and so is open to these models as an alternative to capacity charges. The consultation recognised that, as capacity tariffs and smart meters become more established, other options such as capacity subscriptions may have more value. The consultation highlighted potential risks to consumers of incentivising load shifting or capacity reduction.
Sweden	DNOs have the freedom to design their tariff structure, from a combination of elements. Accordingly, tariffs vary greatly between areas, with some proportion of fixed and variable costs, time-of-use tariffs and capacity based tariffs. In some cases, customers are able to choose between different tariff offers - they have historically been billed directly for their network charge. Frequently, tariffs for domestic customers include a fixed charge, based on their installed capacity (ie fuse size), and a volumetric charge. One tariff option includes a fixed capacity charge as described above, and a variable, ex-post, capacity-based charge, based on the average of the five highest hourly meter readings in peak hours. (There is no variable charge off-peak.)
Germany	Normal household tariffs are volumetric with a fixed charge – they do not have a time-of-use component. However, customers whose individual peak demand differs significantly from the system peak benefit from a 20% lower tariff.
Ireland	For households, there is a fixed charge and a volumetric charge, but no capacity charge. A time-of-use volumetric tariff (day and night) is available to households with a day and night meter, and is applicable to night time storage heating.
France	The regulator has recognised the need for tariffs to evolve through the energy transition and as smart meters become available. They have signalled they expect a balance of capacity and volumetric components are likely to be beneficial, in general, and consider gradual introduction of greater seasonality into charges, in line with the smart meter roll-out, may be desirable. For customers connected at low voltage, they have noted reservations about dynamic peak pricing, given local variations. Many French customers are on a time-of-use retail rate. A long-established tariff for small customers is a form of critical peak pricing, known as 'Tempo'. Consumers are notified a day ahead of the 'rating' for the following day and night, with reduced charges for certain time bands. Trials suggest this has been well accepted by customers and resulted in

[12] NZ Electricity Authority, *More efficient distribution prices—What do they look like?—Consultation paper*, December 2018, pp.11-13. Available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/distribution-pricing-review/consultations/#c17905

	significant response. French distribution network Enedis (EDF) has both a time-of-use volumetric charge and a capacity charge in its tariff. Fuses within the meter may limit usage if the customer's demand exceeds their subscribed capacity.
Portugal	Static volumetric time-of-use tariffs are long-established, with household consumers able to choose between tariffs with one, two or three time periods. The energy regulator has developed the regulatory framework for the introduction of dynamic time-of-use network tariffs. In the long term, they envisage consumers may choose from dynamic options alongside static tariffs.
Spain	Volumetric time-of-use charges exist with up to three time periods for LV users. The proportion of charges for households has recently shifted towards a capacity basis, from around 30% of charges, to 60%. There is some empirical evidence that higher capacity charges have reduced contracted capacity.
Netherlands	Capacity tariffs were introduced in 2009 for small users, requiring customers to nominate a fixed connection capacity. The distribution tariff is composed of this capacity charge and other fixed charges, with no volumetric charge. For a transition period, consumers unable to reduce their capacity have been entitled to compensation, to mitigate distributional effects. Tariffs appear to be set based on six capacity bands, ranging from a 0.05kW band at the lower end, with further increments at 4kW and 10kW, up to a maximum 50kW.
Luxembourg	Tariffs for customers connected to the low voltage networks are currently based on installed capacity, plus a volumetric usage charge. The regulator plans to launch a consultation in late 2018 with a view to implementing a new tariff structure in 2021. Each of the shortlisted approaches involves a capacity charge plus an energy (kWh) charge. Their current leading option for consultation appears to involve (1) the user "subscribing" to a level of firm capacity above which the user is curtailed/faces a surcharge; or alternatively (2) the user subscribing to a level of firm capacity, plus a band of flexible capacity which can be interrupted by the DNO, above which the user is curtailed/faces a surcharge. The intention of this approach is to encourage flexible users such as EV owners to choose option (2), and accept a lower level of firm capacity, and a higher level of flexible capacity, in exchange for paying lower network costs. These options have similarities with some of the access options we are proposing to consider in this review.
Italy	Time-of-use pricing was extended to all households as default in 2010. Previously, there were two set tariffs for households, with a lower capacity limit for primary residences and a higher limit for holiday homes or more intensive users, with tariff rates for households increasing with each kWh block of demand. The bands were set based on a statistical sample of households. Most households have historically had a fuse of 3.3kW, though there is a move to offer greater choice in this capacity limit and charge more cost-reflectively for that capacity. This is lower than a typical UK household would expect to use to meet typical demands associated with white goods, cooking or heating.

	Recent reforms have also introduced more scope for users to define their required capacity – at higher or lower levels, as needed (eg one distributor offers fuses from sizes 0.5kW. Since 2017, network tariffs have included a capacity charge, which is cost reflective for all LV users, ie higher charges apply for users with larger contracted power.

Appendix 2 – Variants of the basic options for demand users

Individual user options

Variations of time of use volumetric options

2.1 The variations for time of use can be developed by answering the following questions:

- What is the type of the Time of Use: non-seasonal or seasonal? Subject to agreed limit?
- How many time bands, when are they, and how long are they?
- How are individual users' HH data used?

Table 3: Variations of time of use options

	Variation 1	Variation 2	Variation 3	Variation 4	Variation 5
Type	Non-seasonal	Non-seasonal	Seasonal (winter months)	Seasonal (winter months)	Subject to agreed limit
Time bands	Two rate on weekdays Time bands determined by DNOs/ESO	Three rate on weekdays Time bands determined by DNOs/ESO	Three rates, with peak an shoulder only implemented during the winter months at higher prices than summer months	More than three rates, with peak and shoulder during the winter months at higher prices than summer months. Time bands could be set in reference to the Electricity Forward Agreement trading products.	Charge based on limit (either negotiated or selected from menu) over specified period (e.g. per day/per month)
HH charging	Assumed demand profile	Actual demand profile	Actual demand profile	Actual demand profile	Actual demand

Variations of actual capacity options

2.2 The variations for actual capacity based charges have been developed by answering the following questions:

- Is the actual capacity charge applied in pre-determined time bands?
- Over what time period is the actual capacity charge determined (monthly/annually)?
- Is the actual capacity charge based on a single period or an average over several periods?

Table 4: Actual capacity based variants

	Variation 1	Variation 2	Variation 3	Variation 4	Variation 5

Time limited	Anytime	Anytime	Peak period, non-seasonal	Peak period, seasonal	Peak period only, seasonal
Monthly or annual	Monthly	Monthly	Resetting annually	12 month rolling ratcheted maximum demand	Resetting annually
How is the demand charge determined?	Based on single highest HH period in month	Average of small number of peaks (up to five)	Average of small number of peaks (up to five)	Based on single highest peak in month	Average of small number of peaks (up to five)

Variations of agreed capacity options

2.3 The variations for agreed capacity based charges have been developed by answering the following questions:

- Is the capacity limit applied in pre-determined time bands? If so, do they apply seasonally?
- What is the impact of breaching the capacity limit?
- For demand charges, over what time period is the demand charge determined (monthly/annually)? Is the demand charge based on a single period or an average over several periods?

Table 5: Agreed capacity based variants

	Variation 1	**Variation 2**	**Variation 3**	**Variation 4**	**Variation 5**
Time limited	Anytime	Peak period, non-seasonal	Peak period, non-seasonal	Peak period, seasonal	Peak period, seasonal
Basis	Individually negotiated capacity level	Individually negotiated capacity level	Menu of capacity bands	Menu of capacity bands Menu of capacity bands	Menu of capacity bands
Impact of capacity breach	Curtailment	Surcharges	Bumped to higher capacity	Surcharges	Bumped to higher capacity

Variations of dynamic charging options

2.4 Variations could include either dynamic time of use or critical peak pricing. The variations for critical peak pricing can be developed by answering the following questions:

- How many critical peak events should there be in the year?
- How long should the time periods for each critical peak event last?
- Should the charges be based on user’s consumption or maximum capacity in that period? Is it full demand in period, or top portion in period?
- How are periods selected? Are the periods standardised (occurring at pre-determined times), at forecasted network constraints or ex-post network constraints?

- How is the critical peak event signalled to users? Forecast warnings or direct instruction/text message/automated/how far in advance? Ex-ante or ex-post notification?

- Could critical minimums also be used in areas (or during times) where generation exceeded demand, in order to encourage more demand? Could negative pricing be applied in such circumstances? (If so, could provide economic incentive to 'resolve' constraint before it arises?)

- Is HH consumption deemed or actual?

Table 6: Dynamic charging variants

	Variation 1 Current Triad	**Variation 2 Modified version of Triad**	**Variation 3**	**Variation 4**	**Variation 5**
No. of critical periods	3	Up to 20	Between 5 and 10	Between 10 and 20	Between 10 and 20
Length of critical peak period	30 minute periods	30 minute periods	Several hours	Several hours	Several hours
Basis of charge	Capacity in half hour, measured in kW	Capacity in half hour, measured in kW	Based on total volume during the critical period, measured in kWh	Based on highest half hour capacity during the critical period, measured in kW	Based on highest half hour capacity during the critical period, measured in kW
Period selection	Periods determined as ex-post peak demand in a season, with at least 10 days separation	Periods determined as ex-post peak demand in a season, with at least 10 days separation	Periods determined based on forecasted network conditions (ex-ante), with small number of days separation	Periods determined based on forecasted network conditions (ex-ante), with no days separation required	Periods determined based on forecasted network conditions (ex-ante), with no days separation required
Signal to users	Forecasts outside of charging design	Forecasts outside of charging design	Suppliers required to signal to users set number of hours ahead	Suppliers required to signal to users set number of hours ahead	Suppliers required to signal to users set number of hours ahead
Use of negative pricing	No	No	No	No	Yes - critical congestion periods may signal to demand users to increase consumption at times of high generation output using negative demand charges
HH data	Deemed	Actual	Actual	Actual	Actual

<u>Variations of critical peak rebate option</u>

2.5 The variations for peak rebates pricing are similar to critical peak pricing and can be developed by answering the following questions:

- How many critical peak events should there be in the year?

- How long should the time periods for each critical peak event last?
- What is the underlying charge design?
- Should the rebate be based on user's volume response (in kWh) or capacity response (in kW) during the period?
- How are periods selected? Are the periods standardised (occurring at pre-determined times), at forecasted network constraints or ex-post network constraints?
- How is the baseline determined?

Table 7: Critical peak rebate variants

	Variation 1	**Variation 2**	**Variation 3**
No. of rebate periods	Between 5 and 10	Between 10 and 20	Between 10 and 20
Length of peak period	Half hour	Several hours	Several hours
Underlying charge design	Flat volumetric	Time of use volumetric	Agreed capacity
Basis of charge	Based on highest capacity response capacity during the peak period, measured in kW	Based on total volume response during the peak period, measured in kWh	Based on highest capacity response capacity during the peak period, measured in kW
Baseline	Historic	Deemed	Agreed

Supplier aggregated options

<u>Variations of time of use options</u>

2.6 The variations are the same for individual user options:

- What is the type of the time of use: daily, seasonal, or dynamic?
- How many time bands, when are they, and how long are they?
- How are individual users' HH data used?
- What is the ratio between peak and off-peak prices?

Table 8: Supplier aggregate volumetric time of use variants

	Variation 1	**Variation 2**	**Variation 3**	**Variation 4**	**Variation 5**
Type	Daily	Daily	Seasonal (winter months)	Seasonal (winter months)	Dynamic
Time bands	Two rate on weekdays Time bands determined by DNOs/ESO	Three rate on weekdays Time bands determined by DNOs/ESO	Three rates, with peak an shoulder only implemented during the winter months at higher prices than summer months	Five rates, with peak and shoulder during the winter months at higher prices than summer months	Half hourly or hourly variations

HH charging	Assumed demand profile	Actual demand profile	Actual demand profile	Actual demand profile	Actual demand profile

Variations of actual capacity options

2.7 The variations are the same as those for the individual user options:

- Is the maximum demand charge applied in pre-determined time bands?
- Over what time period is the demand charge determined (monthly/annually)?
- Is the demand charge based on a single period or an average over several periods?

Table 9: Supplier aggregate maximum demand charging variants

	Variation 1	Variation 2	Variation 3	Variation 4	Variation 5
Time limited	No	No	Yes – daily peaks	Yes – winter peaks	Yes – winter peaks
Monthly or annual	Monthly	Annually	Annually	Annually	Annually
How is the demand charge determined?	Based on single highest HH period in month	Average of small number of peaks (up to five)	Average of small number of peaks (up to five)	Based on single highest peak in month	Average of small number of peaks (up to five)

Variations of dynamic pricing options

2.8 Variations could include either dynamic time of use or critical peak pricing. The variations for critical peak pricing are the same as for individual users:

- How many critical peak events should there be in the year?
- How long should the time periods for each critical peak event last?
- Should the charges be based on user's consumption or maximum capacity in that period? Is it full demand in period, or top portion in period?
- How are periods selected? Are the periods standardised (occurring at pre-determined times), at forecasted network constraints or ex-post network constraints?
- How is the critical peak event signalled to users? Forecast warnings or direct instruction/text message/automated/how far in advance? Ex-ante or ex-post notification?
- Could critical minimums also be used in areas (or during times) where generation exceeded demand, in order to encourage more demand? Could negative pricing be applied in such circumstances? (If so, could provide economic incentive to 'resolve' constraint before it arises?)

Table 10: Supplier aggregate critical peak pricing variants

	Variation 1 Current Triad	Variation 2 Modified version of Triad	Variation 3	Variation 4	Variation 5
No. of critical periods	3	Up to 20	Between 5 and 10	Between 10 and 20	Between 10 and 20
Length of critical peak period	30 minute periods	30 minute periods	Several hours	Several hours	Several hours
Basis of charge	Capacity in half hour, measured in kW	Capacity in half hour, measured in kW	Based on total volume during the critical period, measured in kWh	Based on highest half hour capacity during the critical period, measured in kW	Based on highest half hour capacity during the critical period, measured in kW
Period selection	Periods determined as ex-post peak demand in a season, with at least 10 days separation	Periods determined as ex-post peak demand in a season, with at least 10 days separation	Periods determined based on forecasted network conditions (ex-ante), with small number of days separation	Periods determined based on forecasted network conditions (ex-ante), with no days separation required	Periods determined based on forecasted network conditions (ex-ante), with no days separation required
Signal to users	Forecasts outside of charging design	Forecasts outside of charging design	Suppliers required to signal to users 24 hours ahead	Suppliers required to signal to users set number of hours ahead	Suppliers required to signal to users set number of hours ahead
Use of negative pricing	No	No	No	No	Yes - critical congestion periods may signal to demand users to increase consumption at times of high generation output using negative demand charges

Appendix 3 – Current charge design

3.1 Users are currently charged either DUoS (under CDCM or EDCM) or TNUoS, depending where they are connected to the network, and their connection capacity.

Distribution Use of System charge design

3.2 The table below shows the charge design for all users that are charged DUoS. Groups 1 to 6 are charge CDCM, and group 7 is charged EDCM. The customer group that a user falls within determines the charge design that their supplier is charged on their behalf. Suppliers then choose how to charge their users.

3.3 In the volumetric ToU column, flat means there is no time of use component. Two rate means a there is a peak and off peak rate. RAG (Red, amber, green) means there is a three rate non-seasonal charge. BYG (Black, yellow, green) mean a three rate seasonal charge, where black and yellow are the peak and shoulder periods in the winter months only. Super red is a locational time of use charge only during winter peaks (in London, there is an additional super red period during summer midday peaks).

3.4 For generators, all of the unit charges are considered to be opposites of the demand charge, and so they are paid credits. However, the fixed, agreed capacity, excess capacity and reactive power components are all charges (not credits).

3.5 Note that there are currently no actual capacity, critical peak pricing or critical peak rebate components of charge design for DUoS.

Table 11: DUoS charge design for users

Group	Customer group	GB customer count	Settlement	Volumetric ToU	Actual capacity	Agreed capacity	Dynamic pricing	Critical peak rebate
1	Domestic unrestricted	23,006,965	NHH	flat				
	Domestic two rate	3,893,077	NHH	two rate				
	Small non-domestic unrestricted	1,625,622	NHH	flat				
	Small non-domestic two rate	473,479	NHH	two rate				
2	LV medium non-domestic	2,280	NHH	two rate				
	LV sub medium non-domestic	37	NHH	two rate				
	HV medium non-domestic	27	NHH	two rate				
3	LV network domestic	411,358	HH	R A G				
	LV network non-domestic non-CT	111,002	HH	R A G				
4	LV HH metered	163,452	HH	R A G		✓		
	LV sub HH metered	10,805	HH	R A G		✓		
	HV HH metered	22,554	HH	R A G		✓		
5	NHH UMS category A-D	28,765	NHH	flat				
	LV UMS (pseudo HH metered)	371	HH	B Y G				

6	LV generation NHH or aggregate HH	3,442	NHH	flat (credit)		
	LV sub generation NHH	112	NHH	flat (credit)		
	LV generation intermittent	6,201	HH	flat (credit)		
	LV generation non-intermittent	495	HH	R A G (credit)		
	LV sub generation intermittent	257	HH	flat (credit)		
	LV sub generation non-intermittent	54	HH	R A G (credit)		
	HV generation intermittent	1,960	HH	flat (credit)		
	HV generation non-intermittent	1,249	HH	R A G (credit)		
7	EHV demand (site specific tariffs)		HH	Super red	✓	
	EHV generation (site specific tariffs)		HH	Super red (credit)	✓	

<u>Transmission Use of System charge design</u>

3.6 All licensed suppliers and users connected directly to the transmission network are liable for the forward looking TNUoS demand charges. There are 14 demand zones across Great Britain which correspond to the 14 distribution license areas. Each demand zone has a different TNUoS demand charge.

- Half hourly (HH) metered demand is charged on the basis of "Triad", which is a version of critical peak pricing. Triad periods are determined ex post (i.e. based on actual demand) and are the three highest HH periods during the winter season, separated by at least 10 days. The Triad charge is based on average gross consumption over these three periods. Small distributed generation (capacity less than 100MW) is treated as "negative demand" and may receive a credit for exports over Triad.

- Non-half hourly (NHH) metered demand is charged based on annual net consumption (total demand consumption minus distributed generation) between 4-7pm daily. Domestic or smaller commercial premises through suppliers are generally liable for NHH rather than HH charges.

3.7 Larger generators (those connected to the transmission network and distributed generators with capacity equal to or greater than 100MW), are liable for the forward looking (aka locational) TNUoS generation charges. These charges can be either payments or credits depending on the location (zone) of the generator. There are more generation zones than demand zones. Generation output which is seen as decreasing network costs receives credits and generation output which is seen as increasing network costs make payments. All larger generators are liable for the "wider" locational charges, however, only transmission connected generation is currently liable for the "local" charges.