

Electricity charging arrangements report

Autumn 2016

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1. Where is the vision?

We are currently operating under a charging model designed for a Transmission and Distribution system that is far from what we predict to be required in the future. Indeed the model is already changing with cracks appearing in relation to embedded benefits, triad avoidance, connections and ancillary services. With the increase of distributed generation already on the wires today we are seeing behavioural change and for example the phenomena of exporting Grid Supply Points already manifest. Discussions to establish the current baseline were used to challenge assumptions around how to future proof the charging regime to ensure it is fit for purpose. Building upon our Pathways to 2030¹ report we will also consider charging arrangements for storage.

Ofgem has been instructed to consider Embedded Benefits however it is essential that consideration is given to the interactions and interdependencies within the charging regime, in order to avoid the risk of introducing further distortions, Energy UK members are supportive of an economic and efficient electricity network charging regime with a level playing field for transmission and distribution connected generation as well as demand. The current charging arrangements are extremely complicated and if left unchanged, it is likely that any distortions between transmission and distribution connected generation as well as different types of technology will widen. We note that decisions already made (such as the amount to procure in previous Capacity Market auctions) will have included assumptions on the level of peak demand based on the current regime. We would welcome clarification from Ofgem regarding the direction of travel for future charging arrangements.

2. Executive Summary – key points, impacts and recommendations

There is a concern that the complexity and volume of charging and policy interactions are causing distortions both to transmission and distribution connected generation. Addressing the issues holistically is necessary to ensure that the distortions do not manifest themselves in other areas of the electricity system, as failure to do so could result in ever higher costs faced by GB consumers. There may be specific issues which can be addressed with more urgency than could otherwise be delivered within a wide ranging review, however, ensuring that all issues are taken forward holistically is important to ensure other parties are not unfairly discriminated against. This will help to deliver a charging methodology which is cost-reflective, transparent, stable and predictable, and fair. In any future charging regime, due consideration must be given to the balance between creating appropriate price signals to trigger investment and behavioural change, and the need to protect consumers that may not be in a position to respond to such price signals. Dependent on the nature of the changes proposed, transitional arrangements may need to be considered, where projects that have reached final investment decisions or that have already been built based on either long standing charging principles or policy decisions.

These concerns should inform Energy UK's engagement with Government, DECC, National Grid, DNOs, other trade associations and Ofgem on this topic.

¹ <https://www.energy-uk.org.uk/publication.html?task=file.download&id=5722>

Due to the diverse range of businesses within our membership, there are different views within several specific areas and hence recommendations focus on areas of agreement or principle.

The scope of this report was discussed and set at the initial workgroup meeting with the following topics considered in scope:

- Distribution Use of System (DUoS)
- Transmission Network Use of System (TNUoS)
- Balancing Services Use of System (BSUoS)
- Connection charging (transmission and distribution)
- Net vs Gross charging
 - Capacity Market Supplier Levy
 - Triad
- Green policies

Other areas that were also noted as being important included the ancillary services market, distribution/transmission losses, access to the wholesale market and the transition from Distribution Network Operators (DNOs) to Distribution System Operators (DSOs). Due to the limited time available to produce this report these topics were considered to be out of scope for this piece of work. It was agreed that these areas were considered out of scope for this charging report but that these areas would be progressed within Energy UK separately.

The table below contains a summary of the key issues, impacts and recommendations in this report.

Issue	Impact	Recommendation
Transmission Network Use of System		
An increasing share of a rising total TNUoS charge is being collected from a shrinking demand charging base, which is resulting in a large increase in the demand TNUoS residual charge.	Higher Half Hour (HHH) demand tariffs are driving increased Triad avoidance which in turn is pushing up the charges for other customers. The value of the Half Hour demand tariff which is recovered through Triad avoidance appears disproportionate and will incentivise generators to connect to the distribution network to access this benefit.	Energy UK considers that the methodology for how the TNUoS residual element is recovered should be reviewed to provide an enduring and sustainable charging regime. Any long term solution should be cost reflective and should investigate different ways in which charging can be applied. Ensuring that the framework can be futureproofed as far as possible while allowing a framework to evolve over time is crucial.
The European Commission regulation 838/2010 has not been reviewed as expected.	Although the general direction of travel is for greater harmonisation with Europe the €2.50 cap has not been updated resulting in the cap now being outdated.	Ofgem should progress discussions with the European Commission to review and update this regulation and also work towards greater harmonisation within Europe.
Charging Principles		
Behind the meter generation and turn up Demand Side Response can avoid policy costs charged on a Net/Gross basis.	Generation will be incentivised to move behind the meter to avoid network charges and policy costs.	Ofgem should consider how behind the meter generation and turn up Demand Side Response (DSR) are charged in the future.
Exporting Grid Supply Points		
Traditionally GSPs have existed for the purpose of delivering energy to a distribution network. However, because of the growth	Exporting GSPs have an impact on the transmission network and currently there is no methodology in place to	We believe the issue of exporting GSPs should be considered as part of a holistic review of the TNUoS charging

in generation connected at distribution level, increasingly GSP's are also being required to export power onto the transmission network.	charge for the use of transmission system.	methodology. It is our view that a successful implementation of charging arrangements on exporting GSPs will depend greatly on a number of factors which are not yet addressed in any great detail.
Triad		
Triads appear to be becoming harder to predict and demand peaks are occurring outside of historic Triad months over the winter ² .	We are seeing shoulder periods on either side of a Triad as generators run and demand turn down which can cause additional stress on the system affecting operability as demand patterns change.	Energy UK considers that a review of the Triad itself should be undertaken by National Grid to consider whether the three peaks used for network charging are effectively avoiding network reinforcement.
Interconnection		
Network charging methodologies vary considerably across Europe with volumetric, capacity and locational charges all used to calculate tariffs. Comparing these charges on a like for like basis would be extremely challenging with differences in methodologies not always comparable with other Member States. Addressing the issue of different tariffs/policy costs across Europe must take account of the whole system and market arrangements to ensure these are cost reflective.	GB generation may not be charged consistently compared with generation in Europe.	Ofgem should assess options for introducing cost reflective network charging (balancing and transmission) so levels are harmonised for GB generators via-a-vis the rest of the EU, as far as possible within EU rules and ACER's work on tariffs. Ofgem should also lead the debate in Europe advocating cost reflective transmission charging within the internal electricity market, based on the GB model, to minimise any distortions of cross-border trade.
Ofgem's development of the Cap and Floor regulatory model has been successful in promoting additional interconnector investment. Ofgem has not factored interactions with other policies which might lead to consumers losing out e.g. impacts to TNUoS charging.	An inefficient amount of interconnection may lead to higher costs than necessary. For example, closure of GB generation as a result of displacement would be difficult and costly to reverse in the scenario that extra plant is subsequently found to be needed.	Ofgem should consider the interaction between cap and floor and TNUoS recovery (as well as other government policies). This needs to be considered to give a fuller and more integrated assessment of the costs, benefits and impacts.
Regulatory treatment of interconnection is inconsistent. Under the Third Package interconnectors are TSOs but are treated as "quasi generation" for GB Capacity Market participation purposes.	Interconnection participation increases competition in the CM with potential benefits to GB consumers through a lower clearing price. We recognise that this is intended to be a short term solution, but it could lead to inefficient GB plant closures if de-rating of interconnectors is too optimistic and leads to under procurement (or structural	Interconnectors need to be regulated consistently across European and GB frameworks. Lobby DECC to move away from direct participation of interconnector owners in the CM to cross border participation by capacity providers as soon practicable De-rating of interconnectors within the Capacity Market

² It should be noted that this has only occurred once, however, should this trend continue, there would be more emphasis on carrying out this review.

	over-supply in GB electricity market if derating is too pessimistic).	should not be overly optimistic nor overly pessimistic.
Balancing Services Use of System		
The range of products which now make up BSUoS charges has expanded with many products performing different functions and providing different signals for example black start.	BSUoS charges may no longer be representative with some products not used solely to balance the system.	National Grid should conduct a full review of the range of components contributing to BSUoS charges.
BSUoS is calculated ex-post with the charge only appearing 5 days after the HH, this makes it incredibly hard to predict.	BSUoS does not provide a useful price signal to allow all generators to respond to the needs of the system.	In conjunction with the above recommended review of what products should be included in BSUoS, Ofgem should: <ul style="list-style-type: none"> ➤ Review the composition and purpose of BSUoS and identify where generation/demand have the ability to respond to various elements of BSUoS (thus removing the risk of BSUoS variability) These elements can then be separated into fixed and variable charges which contribute to the overall BSUoS charge. ➤ Once CMP250³ has been submitted to Ofgem for determination, Ofgem should consider this in conjunction with the above point.
BSUoS is only paid by transmission connected generation and demand users (50%/50%). Distribution connected generation does not pay for BSUoS although arguably it benefits from a stable electricity network.	The avoided cost of distribution connected generation may cause a distortion in charging arrangements especially where Distribution connected Generation provide services to the System Operator.	Ofgem should consider whether Distributed Generators which cause system costs should contribute towards the costs of balancing the network.
Distribution Use of System		
Whilst the CDCM is the same for all DNOs, with the EDCM having two versions, this makes distribution charging methodologies complicated and inputs vary between DNOs. This makes comparing charges between DNOs difficult.	<p>The CDCM is fully transparent with all models available DNO charging statements, EDCM also appear in charging statements.</p> <p>Customers, therefore find comparison of charges (particularly EDCM) difficult due to lack of availability of the supporting models and difference across the six DNOs.</p>	<p>Ofgem should undertake a review of the CDCM with a view to streamlining the methodology and improving transparency.</p> <p>Ofgem should also ensure improved transparency of the EDCM and require publication of the EDCM models. Further work is required to ensure as much consistency and coordination of updates across all six DNOs to aid the process</p>

³ CMP250 'Stabilising BSUoS with at least a twelve month notice period'

		of comparison well ahead of new charging periods.
A review of the EDCM has been carried out to investigate the issues that have arisen since the implementation of the EDCM.	Several recommendations have been made to improve the EDCM.	Ofgem should progress the proposed remedies highlighted in the EDCM review.
Stability of charging especially for EHV metered sites is not robust and can vary significantly depending on whether more generation joins the network or demand leaves.	Uncertainty around future charging tariffs can have a significant impact on a developer's decision as to whether to build a power station.	Ofgem and DNO's should review long term forecasting of distribution network charges to consider where additional clarity can be given regarding future costs.
Connections		
Distribution connection charges can vary considerably with the network only being reinforced once generation has committed to building.	The distribution network is under developed with no strategic investment taking place which impacts the ability of generation to build projects.	<p>We support Ofgem's work to allow alternative network investment to take place sooner and to free up un used capacity in the connection queue.</p> <p>We support the adoption of more smart flexible connection terms allowing non-firm connections to progress.</p>
Thermal generation trying to connect to the transmission network using connect and manage cannot always justify connection agreement due to the high probability and cost of being constrained off the network.	Thermal generation is not able to connect to the network using connect and manage, therefore, location signals are not being used to locate plant.	Ofgem should consider how strategic network investment can be progressed taking account of future network constraints.
Capacity Market Supplier Levy		
The Capacity Market Supplier Levy is calculated on a net basis.	Distributed Generation (DG) is paid to avoid the cost of the CM applied to customers creating a double benefit for DG.	<p>Energy UK recommends that the CM Supplier Levy be applied on a gross basis in the future in the same way that the CfD Supplier Obligation is applied. DECC has confirmed that it intends to do this in time for the 2017/18 delivery year.</p> <p>Behind the meter generation and turn up, Demand Side Response will also have to be addressed as these can also avoid charges even if the levy is recovered on a gross basis.</p>
Policy costs (FiT, RO, CfD)		
Embedded generation and storage, sitting within the grid supply points is exposed on its import of energy from the Grid to the attribution of supplier	DG face costs which transmission connected generation are not exposed to.	The costs of green policies (FiT, RO, CfD, CM and AAHEDC) which are applied to Distributed Generation should be taken into account when

charges. This is also the case for embedded storage.		considering what embedded benefits are received.
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1. Introduction

The GB electricity system has undergone significant changes over the past 20 years. Historically, the system was built on the premise that large prominently baseload power stations connected to the transmission network with demand customers connecting at the distribution network level. Following the increase in renewable generation we now operate a system with over 20GW of generation connecting to distribution networks creating a much more dynamic system which has a significant impact on the level of recovered network costs.

The changes to the dynamic of how charging, connections and policy now interact with transmission and distribution connected generation is not a new concept and is something that has been discussed within industry for the past 20 years. Embedded benefits often feature at the centre of these debates.

It is apparent that with the current trend towards more decentralised generation that there is a requirement to review methodologies around how the cost base for transmission and distribution use of system are recovered. Understanding what is meant by “embedded benefits” is also important to ensure that the debate around whether the costs are appropriate should be focussed on reviewing the right policies.

We consider that the below key principles should form the basis for the current and future electricity charging structures:

- **Cost reflectivity** – Transmission and distribution connected generation should be exposed to charges that are appropriate and cost reflective taking into consideration the impact on the rest of the network. We support the principle of using peak demand as the basis for relevant elements of network charging to reduce peak electricity demand and avoid network reinforcement. The value of charge avoidance as well as the wholesale electricity price should be considered together when looking at how to manage these peaks.
- **Locational signals** – We support locational signals as a means to provide a clear indication of the optimal site to gain the best rewards for locating generation near to demand (and visa versa). Such signals must be cost reflective to drive appropriate behaviour from market participants in conjunction with other price signals in the market. This ensures the efficient development of the Main Integrated Transmission System (including the distribution network) to ensure the most efficient use of assets.
- **Market signals** – Market signals should allow participants to respond to price signals allowing for the efficient operation of the system. Therefore, where such signals only become apparent ex-post and the ability to forecast these signals is limited, consideration should be made as to whether to adopt a fixed, forecastable charging methodology.
- **Stability and predictability** – Stability and/or predictability are important elements of a charging regime helping generators/demand to accurately forecast revenue and thus providing additional certainty, aiding investment decisions. We note, however, that there are some trade-offs between cost reflectivity and stability of charges.
- **Europe** – The range of different charging methodologies across Europe creates a very complex system which is hard to compare with GB on a like-for-like basis. Greater harmonisation of tariff structures with Europe should be promoted to ensure generation across EU Members States competes on a level playing field.
- **Long term outlook** – Any recommendations to change the structure of network charging should consider the extent possible future changes to the use and management of energy consumption. New developments to consider include smart metering, smart networks combined with moves towards the wider utilisation of electric heating and the electrification of transport. Generation will continue to decarbonise with more renewables and peaking plant in the future along with storage and Demand Side Response (DSR).
- **Transparency** - For participants to understand the charging arrangements and more importantly respond to them it is important that they are fully transparent. This means that the

charges should be clear along with the methodologies used to set them. Additionally, information should be provided on any assumptions and data used to set charges.

2. Transmission connected generation

Transmission connected generation is subject to three types of transmission charges⁴; connection charges, Transmission Network Use of System (TNUoS) charges and Balancing Services Use of System (BSUoS) charges. TNUoS recovers the cost of Transmission Owner activities for the three onshore TOs (National Grid, SHET and SPT), Offshore Transmission Owners (OFTOs) and the Network Innovation Competition; in future it is expected to also recover the costs of the Competitively Appointed Transmission Owner (CATO) regime for onshore competition, and interconnector cap and floor. BSUoS recovers the costs associated with balancing and operating the system for National Grid in its role as system operator. Connection Charges recover the cost of single user transmission assets for the onshore TOs. The charging methodologies are reviewed below.

Transmission Network Use of System

TNUoS charges recover the cost of installing and maintaining the shared transmission system assets that cannot be attributed to a single user in England, Wales, Scotland and offshore assets. Generation TNUoS is paid by all transmission connected generation and by licensable embedded generation (i.e. 100MW or larger).

TNUoS is set using an ex ante methodology, and tariffs are currently published two months⁵ prior to them applying. Different variables affect what transmission customers are charged to recover the cost of the operation of the system, such as which geographical zone the generation or supply is located and its size, and the physical characteristics of the network they are attached to. The 'locational' element reflects the different costs that network users impose on the network depending on where the connection is located. The 'residual' element is set to recover the remaining "allowed revenue". The overall TNUoS is allocated to generation (G) and demand (D) network users through the 'G:D split'. Historically, the total TNUoS revenue was split 27% to Generation and 73% to Demand, however, EU Regulation 838/2010 has seen the generation percentage fall over recent years due to the €2.50/MWh cap on average annual transmission charges (Figure 1 shows the current trend in the G:D split).

Figure 1- Historic and future generation percentage of TNUoS revenue

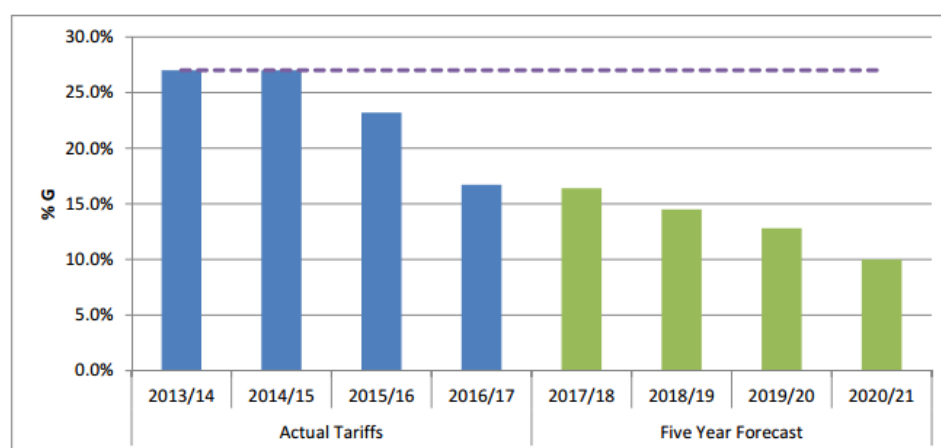


Figure 1: Historic and future forecast generation percentage of TNUoS revenue

⁴ There are costs for example within TNUoS relating to the largest in-feed loss that could be attributed to generation.

⁵ CMP244 is looking to extend this to 200 days, and this proposal is currently with the authority to decide.

£2.7bn of TNUoS is due to be recovered in 2016/17 to cover the transmission network costs for: National Grid Electricity Transmission (NGET), Scottish Hydro Electric Transmission (SHET), Scottish Power Transmission (SPT), the Offshore Transmission (OFTO) regime and Network Innovation Competition. In the future, TNUoS will also include the interconnector 'Cap and Floor' and competitively appointed transmission owners (CATO) costs.

European regulation EC838/2010

EU Regulation 838/2010 limits average transmission charges for generators in European Union member states⁶. The range of allowable average transmission charges for generators in Great Britain (GB) is €0-2.5/MWh, and the range for most other EU countries is €0-0.5/MWh. In GB, the charge is set ex ante by forecasting the annual output of transmission generation, and using a specified exchange rate; this gives a total amount of revenue to be recovered from generation.

This leads to two issues:

- The first relates to the amount of TNUoS recoverable from transmission connected generation capped at €2.5/MWh and the fact that the cap is not index linked. This will effectively reduce the amount recoverable from generation over time.
- The falling level of cost recovery from transmission connected generation also means the amount recovered from demand will increase over time.

Both of these points mean that any surplus TNUoS must be recovered from the demand element of TNUoS. The graph below shows the impact on the level of TNUoS revenue collected by generation and the percentage forecast of the G element.

Demand TNUoS

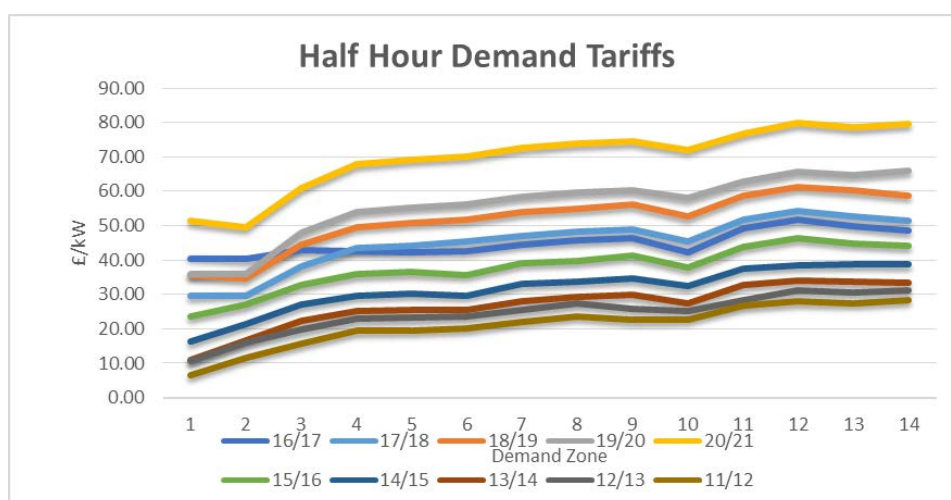
TNUoS is levied on demand taken from the transmission system at the Grid Supply Point. There are two methodologies for charging Demand TNUoS. For customers who are half-hourly metered, they are charged on a "triad" basis. That a locational £kW tariff is applied based on their average output during the three winter triads – the three settlement periods of highest system demand separated by 10 days, between November and February. If you take no output during this period, you do not pay any TNUoS charge.

For customers who are not half-hourly metered, they are charged based on their annual usage between 4pm and 7pm each day. This is calculated based on their meter reading and the profile classes. The total volume of energy (KWh) is multiplied by a p/kWh tariff to provide a charge.

The cap on the amount of TNUoS recoverable from generation means that the demand element of TNUoS is increasing. Changes to HH demand tariffs since 2011/12 are shown below (Figure 2) which are forecast out to 2020/21. The impact of recovering the residual element is set to change significantly over the coming years.

⁶ This does not apply to distribution charges for generators.

Figure 2 - HH demand tariffs 2011/12 - 2020/21



This issue has also been discussed in several CUSC modification working groups with CMP224 highlighting the issue of the offshore transmission network substantially increasing the revenue collected by National Grid. The impact of these assets is shown below as generation only spurs (Figure 3). The decision to increase the level of offshore wind farms is a government decision as we progress to a decarbonized power sector. An increasing total TNUoS charge is being collected from a shrinking generation charging base (i.e. less electricity is being produced from transmission connected generation). The demand charging base is also shrinking, which is resulting in a large increase in the demand TNUoS residual charge (i.e. higher unit rate of demand tariffs).

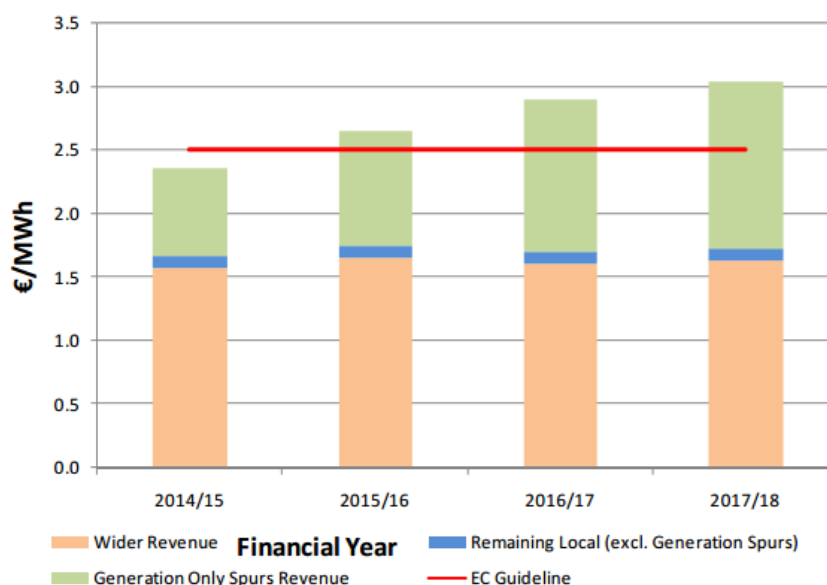
The future Transmission Owner revenue forecast is provided below which shows how recoverable revenue is increasing. This is taken from National Grids five year TNUoS forecast⁷. Below that is a graph showing the interaction between the forecast revenue and the €0-2.5/MWh cap on generation charges.

⁷ <http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/>.

Figure 3 – Generation Only Spurs

£m Nominal	2016/17	2017/18	2018/19	2019/20	2020/21
National Grid					
Price controlled revenue	1,828.2	1,806.4	1,867.8	1,939.1	2,189.1
Less income from connections	42.7	46.5	47.9	47.9	47.9
Income from TNUoS	1,785.5	1,760.0	1,819.9	1,891.2	2,141.2
Scottish Power Transmission					
Price controlled revenue	306.4	347.1	415.1	404.8	412.7
Less income from connections	11.8	13.9	14.1	14.4	14.7
Income from TNUoS	294.6	333.1	401.0	390.4	398.0
SHE Transmission					
Price controlled revenue	326.2	328.5	323.8	333.2	338.7
Less income from connections	3.4	3.6	3.7	3.8	3.9
Income from TNUoS	322.8	324.9	320.1	329.4	334.8
Offshore	260.8	276.5	401.6	523.3	875.0
Network Innovation Competition	44.9	40.5	40.5	40.5	40.5
Total to Collect from TNUoS	2,708.7	2,735.0	2,983.1	3,174.7	3,789.5

Figure 4 – Annual average Generation TNUoS Revenue Components (Slow Progression)⁸



The residual element of TNUoS is collected from demand to make sure that National Grid is paid the correct total amount of revenue. The total demand residual element of TNUoS being recovered from Triad may, therefore, not be considered as cost reflective. Whether a customer, or a generator consumes/generates at peak, it is the locational elements of the tariff which exists to provide an appropriate economic price signal for siting generation and demand. We note that the locational signal is only one element contributing to the decision to where demand/generation connects. Other factors include wider infrastructure availability, skilled labour, risk of flooding etc. Once connected, the total costs (including residual) determines whether you use the system at all, wherever you're sited.

⁸ Taken from the CMP224 Final Workgroup Report

Project TransmiT

In September 2010 Ofgem launched Project TransmiT, an independent and open review of electricity transmission charging and associated connection arrangements. The aim of the project was to ensure that we have in place arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure and high quality network services at value for money to existing and future consumers. The three issues outlined in Ofgem's direction included:

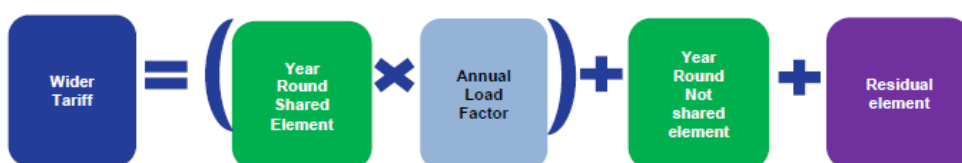
- Better reflect the costs and benefits imposed by different types of generators on the electricity transmission network;
- Take into account the potential Scottish island links that are being considered; and
- Take account of the development of "bootstrap" High Voltage DC (HVDC) links.

In July 2014, Ofgem decided to approve an option for change under the CUSC charging arrangements known as WACM 2 and implement this from April 2016. The below graphic shows how the new charging methodology works.

Conventional Generator



Intermittent Generator



Each generator has a specific annual load factor based on its performance over the last five years. Where new plant does not have at least three complete charging year's history then generic load factors specific to the technology are also used.

Any sudden changes to the current embedded benefits regime that investors perceive as retrospective could increase costs of capital for a wider range of energy projects reflecting increased regulatory and political risk. The removal of embedded benefits is likely to increase the price at which Distributed Generation bids into future Capacity Market auctions. This will shift the supply curve of participating plant upwards, and could increase the clearing price in future auctions compared to the status quo, although these impacts are highly uncertain at this stage. Additionally, changes to embedded benefits would impact projects which have already secured CM agreements in previous auctions which are locked into the CM clearing price but without the revenue that may have been factored into CM bids.

Issue	Impact	Recommendation
An increasing share of a rising total TNUoS charge is being collected from a shrinking demand charging base, which is resulting in a large increase in the demand TNUoS residual charge.	Higher Half Hour demand tariffs are driving increased Triad avoidance which in turn is pushing up the charges for other customers. The value of the Half Hour demand tariff which is recovered through Triad avoidance appears disproportionate and will incentivise generators to connect to the distribution network to access this benefit.	Energy UK considers that the methodology for collecting the methodology for how the TNUoS residual element is recovered should be reviewed to provide an enduring and sustainable charging regime. Any long term solution should be cost reflective and should investigate different ways in which charging can be applied.

		Ensuring that the framework can be futureproofed as far as possible while allowing a framework to evolve over time is crucial.
The European Commission regulation 838/2010 has not been reviewed as expected (is it not a legal requirement to review this? If so the word expected needs to change by the 1st January 2016.	Although the general direction of travel is for greater harmonisation with Europe the €2.50 cap has not been updated resulting in the cap now being outdated.	Ofgem should progress discussions with the European Commission to review and update this regulation and also work towards greater harmonisation within Europe.

Charging Principles

The current charging arrangements work on the basis of net flows and benefits/credits are calculated and assigned accordingly so that the correct balance is maintained. It is important to note that while net charging may be suitable for collecting some costs such as avoiding network reinforcement, it may also not be appropriate as a mechanism to collect some other charging/policy costs.

Net vs. gross charging

There is a debate ongoing as to whether flows across grid supply points (GSPs) should be charged on a net or gross basis. Net flows at GSPs relate to the consideration of net demand flowing into or out of a GSP. Gross flows consider separately the flows to demand consumption (positive demand) from the transmission system and the flows from embedded generation (negative demand) to the transmission system. Net charging would consider the net demand at each GSP/GSP Group and is the process used in the existing TNUoS methodology. Gross charging would consider flows separately and would charge on both positive and negative demand bases.

Arguments for net charging

Industry generally considers flows between connected networks on a net basis. A move to gross charging could be considered inconsistent with this approach. Proponents of net charging argue that net flows onto and off networks trigger investment to a greater extent than gross flows; if generation and demand were balanced locally then there would be a reduced need for transmission assets. In a hypothetical situation where every GSP had sufficient embedded generation (with redundancy) to meet gross positive demands at all times there would be no need for a transmission system.

In a focus group organised by National Grid to discuss the issue, a majority of industry participants expressed a preference for a net charging approach⁹.

Arguments for gross charging

National Grid has previously presented a case for gross charging, suggesting that 1MW of positive demand should not be treated any differently than another MW of demand in the charging methodology, and therefore all demand should be charged on a gross basis. Any benefit provided by or to embedded generation should be made explicitly outside of this consideration.

Behind the meter generation and demand

Behind the meter generation is where a generation facility is located behind the meter on the owner's property where the intention is that the power is for on-site consumption. This can range from CHP plant at an industrial facility through to solar PV panels on domestic rooftops. The majority of behind the meter generation is net metered allowing the user to net off charges such as TNUoS and BSUoS

⁹ 'Review of the Embedded (Distributed) Generation Benefit arising from transmission charges', <http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/>

which are currently charged on a net basis. Behind the meter generation/storage and turn up Demand Side Response can also avoid gross charges as these can be netted off. This means that there is an incentive to locate generation behind the meter to avoid these costs. If changes are made to how policy costs are recovered from the distribution connected generation and demand for example moving from net to gross charging for the CM Supplier Levy then work also needs to be done to consider how behind the meter generation/storage and demand is treated.

Issue	Impact	Recommendation
Behind the meter generation and Demand Side Response can avoid policy costs charged on a gross basis.	Generation will be incentivised to move behind the meter to avoid network charges and policy costs.	Ofgem should consider how behind the meter generation and Demand Side Response are charged in the future.

3. Triad

The Triad system was designed to incentivise HH metered energy users to reduce energy consumption at times of peak demand. This therefore avoids the cost of reinforcing the network by managing peak demand. Dealing with peaks in electricity demand - particularly during the winter months - is one of the key challenges facing the system operator.

The total network charge which industrial and commercial users must pay is made up of two elements. The first is a tariff based on geographical location and the second, the residual, is as described above. These tariffs are then multiplied by users' average consumption of grid electricity during the three half-hourly periods of highest demand between November and February referred to as the Triad periods.

Given that for most users geographical location is fixed, users' ability to control their network charges is limited to reducing electricity consumption or by switching to behind the meter generation during the Triad periods. If specific users do not draw power from the grid in the three Triad half-hours, then they pay no TNUoS charges for the entire financial year. Domestic customers with smart meters are not yet affected by Triads (as their tariffs are based on assumed consumption profiles).

Issues and challenges

The Triad system offers an opportunity for users to avoid significant charges for annual usage by minimising consumption in three periods totalling only 90 minutes of usage. It is likely that in order for a user to hit these periods, consumption would need to be minimised across the winter whenever peaks may potentially arise. Indeed, the system is specifically designed to incentivise such behaviour though the exact timing of Triads is uncertain and only calculated *ex post*. Nevertheless, Triad-avoiding users may reduce consumption in very specific periods, hit the Triads, use the transmission system at other times and yet pay very little in the way of costs for the transmission network, however, they will not have caused additional infrastructure costs due to their behaviour. The investment in the network, and therefore its cost, determined by peak consumption, would therefore have been based on demand from other users (or overinvestment in the network). Conversely, other users may make relatively little general use of the transmission network but find themselves unable to turn down consumption or switch to non-grid supplies during Triad periods. Such users would thus be obliged to pay significant costs potentially greater than those of other users making much greater annual use of the transmission network. The enduring Triad charging methodology should reflect the cost of avoided investment in infrastructure but may not be appropriate for the recovery of all network charges and policy costs.

Under current arrangements, revenue from transmission charges is to remain constant. A decrease in net demand will therefore lead to an increase in the demand residual as the number of users drawing power from the grid and so paying transmission charges decreases. Costs increase for those users that remain on the grid. Some users have limited capacity to reduce consumption of grid supplies. A steadily decreasing number of such users is therefore likely to be obliged to pay steadily increasing transmission charges. The payment of transmission charges is consequently a zero sum game. Therefore one party's benefit comes at another party's expense. In the case of embedded generators

this holds true. It gains from allowing some suppliers to avoid charges or indeed can sometimes benefit directly through negative charges, but suppliers as a group still pay the same amount of TNUoS and BSUoS in total. Therefore, their gain comes at the expense of higher charges for other demand users.

Following on from this, the principle of maintaining the revenue from transmission charges at a constant level steadily increase the value of embedded benefits. An increase in the volume of embedded generation will offset demand for transmission connected generation and so further increase the demand residual. The more embedded generation connects to the Grid, the greater the reduction in demand for transmission-connected generation, the greater the increase in the demand residual and the greater the value of avoiding this charge. The cycle is therefore self-reinforcing. We are now in a scenarios where the Triad avoidance embedded benefit from the demand residual will continue to increase under a 'do nothing' scenario. A solution is therefore required to address the spiralling cost of the demand residual element while also retaining a signal to manage Triad effectively. With the demand residual element of TNUoS forecast to continue rising, it is likely that any distortions between transmission and distribution connected generation as well as different types of technology will widen. Energy UK considers that the methodology for collecting the TNUoS residual element is recovered should be reviewed to provide an enduring charging regime.

The timing of Triads is not known in advance. National Grid uses settlement data to calculate the Triads in the March after the Triad season. For users to benefit from lower network charges, then each must, therefore, anticipate before the event when the half hourly triad peaks may occur and take action to avoid all such potential peaks (suppliers also provide Triad warnings as a service). This has the effect of reducing peak demand across the Triad season.

Issue	Impact	Recommendation
Triads appear to be becoming harder to predict and peak demand is also occurring outside of historic Triad months over the winter ¹⁰ .	We are seeing shoulder periods on either side of a Triad as generators run and demand turn down which can be cause additional stress on the system as demand patterns change.	Energy UK considers that a review of the Triad itself should be undertaken by National Grid to consider whether the three peaks used for network charging are effectively avoiding network reinforcement.

4. Exporting GSPs

Grid Supply Points (GSPs) provide the interface between the transmission system and distribution networks. Traditionally GSP's have existed for the purpose of delivery of energy to a distribution network, however because of the growth of generation connected at distribution level increasingly GSP's now export power onto the transmission network with the flow of power also being significantly altered.

The majority of GSPs provide a connection for a single customer (usually DNO's). At such sites sole use assets are categorised as connection assets with costs recovered from that single customer as connection charges. In the case of DNOs the costs are then passed on to network users as exit charges. Some GSPs connect multiple parties. At these sites all assets¹¹ are considered to be part of the infrastructure of the main transmission system. These costs are recovered through TNUoS charges. Currently, those costs associated with sole asset sites are socialised across all parties on a

¹⁰ It should be noted that this has only occurred once, however, should this trend continue, there would be more emphasis on carrying out this review.

¹¹ All sole use assets are charged to the specific DNO. Where GSPs have multiple parties then it can be the case that more assets are deemed shared and there for recovered through TNUoS. So for example where there is a single connectee the transformer and circuit breaker might be sole use, whereas if the GSP is shared then only the circuit breaker might be sole use.

capacity basis for half hourly metered customers and a commodity basis for non-half hourly metered customers.

We believe the issue of exporting GSPs should be considered as part of a holistic review of the TNUoS charging methodology. It is our view that a successful implementation of charging arrangements on exporting GSPs will depend greatly on a number of factors which are not yet addressed in any great detail.

It is our view that a successful implementation of charging arrangements on exporting GSPs will depend greatly on a number of factors which are not yet addressed in any great detail. Ensuring that the right signals are being sent to distribution connected generation and demand to ensure the charging regime is cost reflective is something that must be taken forward with National Grid, DNOs and industry.

Issue	Impact	Recommendation
Traditionally GSPs have existed for the purpose of delivering energy to a distribution network. However, because of the growth of generation connected at distribution level, increasingly GSP's are also being required to export power onto the transmission network.	Exporting GSPs have an impact on the transmission network and currently there is no methodology in place to charge for the use of transmission system.	We believe the issue of exporting GSPs should be considered as part of a holistic review of the TNUoS charging methodology. It is our view that a successful implementation of charging arrangements on exporting GSPs will depend greatly on a number of factors which are not yet addressed in any great detail.

5. Interconnection

Unlike GB generators and demand users generation flowing across interconnectors do not pay TNUoS or BSUoS charges which we consider is in line with the requirements of the Third Package.

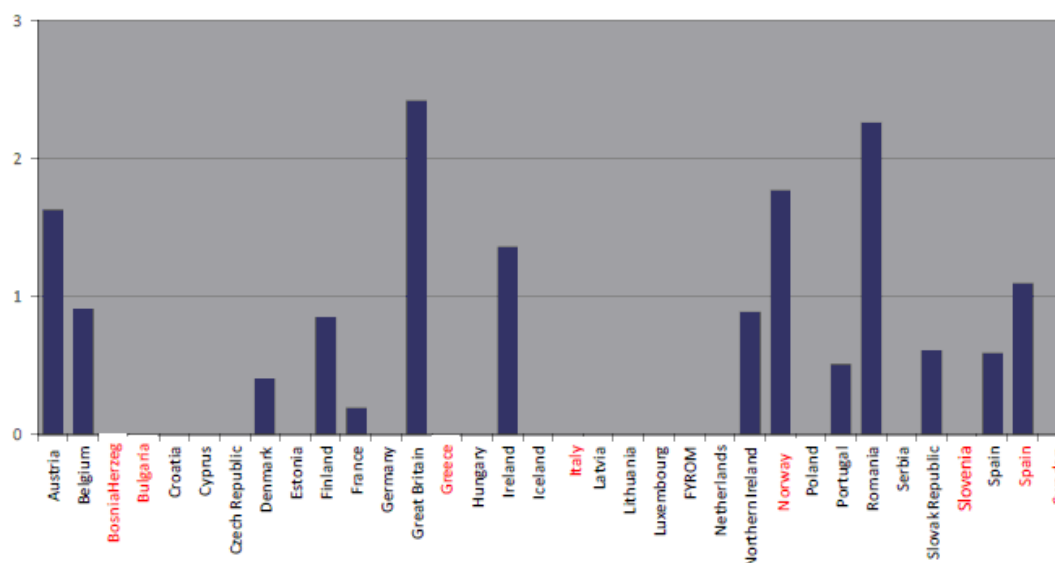
ENTSO-E's review of network charges which was published in July 2014¹² gives an indication of generation charges applied throughout Europe. This work compares the main Characteristics of the Transmission System Operator (TSO) tariffs in Europe. Figure 1 below shows the generator components of the transmission tariffs in 2014.

ACER notes that different levels of power-based G-charges (€/MW) or lump-sum G-charges, as long as reflective of the cost of providing transmission infrastructure services to generators, can be used to give appropriate and harmonised locational signals for efficient investments in generation. For example to promote locations close to load centres or where the existing grid can accommodate the additional generation capacity with no or minimal additional investments.

¹² https://www.entsoe.eu/publications/market-reports/Documents/SYNTHESIS_2014_Final_140703.pdf

Figure 5 – G components of the unit transmission tariffs in 2014¹³

Euro per MWh



Although ENTSO-E's overview provides a high level representation of generator charges across Europe there is not complete transparency of charges in different European countries and within the ENTSO-E report there is a huge variety and complexity in the component costs included in those tariff calculations. Whilst it would appear that other European generators may not be subject to transmission charges as high as those in GB, generators may be subject to other charges, such as deep/shallow connection charging, imbalance costs and other special charging arrangements that those in GB are not.

TNUoS makes up a significant amount of a generator's fixed cost along with for example business rates and staff expenditure. GB uses locational charging as a means to provide signals to promote the efficient development of the Main Integrated Transmission System (MITS). The costs applied to generation and demand users vary, for generation users, from negative charges in the south of the country to very high costs in Scotland.

A regulated route known as "cap and floor" ensures that revenues generated by a new interconnector are held between a band determined by Ofgem based on projected costs. Any costs within the cap and floor regime are subsequently recovered by TNUoS charges on transmission users. As well as increasing overall revenue allowances for TSOs, which will largely fall to demand users, because of the aforementioned cap on generators, this will manifest in a higher demand residual charge and therefore a stronger signal to embedded generators. Moreover, as the level of interconnection increases the amount of domestic generation paying TNUoS decreases due to being replaced by foreign imports, which will further increase the demand residual charge. As the government has committed to new interconnection (to the order of 9 GW), under the current charging regime this rise in TNUoS cost can be considered unavoidable.

Issue	Impact	Recommendation
Network charging methodologies vary considerably across Europe with volumetric, capacity and locational charges all used to calculate tariffs. Comparing these charges on a like for like basis would be extremely challenging with differences in	GB generation may not be charged consistency compared with generation in Europe.	Ofgem should assess options for introducing cost reflective network charging (balancing and transmission) so levels are harmonised for GB generators via-a-vis the rest of the EU, as far as possible within EU rules and ACER's work on tariffs.

¹³ ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2014

methodologies not always comparable with other Member States. Addressing the issue of different tariffs/policy costs across Europe must take account of the whole system market arrangements to ensure these are cost reflective.		Ofgem should also lead the debate in Europe advocating cost reflective transmission charging within the internal electricity market, based on the GB model, to minimise any distortions of cross-border trade.
Ofgem's development of the Cap and Floor regulatory model has been successful in promoting additional interconnector investment. Ofgem has not factored interactions with other policies which might lead to consumers losing out e.g. impacts to TNUoS charging.	An inefficient amount of interconnection may lead to higher costs than necessary. For example, closure of GB generation as a result of displacement would be a difficult and costly to reverse in the scenario that extra plant is subsequently found to be needed.	Ofgem should consider the interaction between cap and floor and TNUoS recovery (as well as other government policies). This needs to be considered to give a fuller and more integrated assessment of the costs, benefits and impacts.
Regulatory treatment of interconnection is inconsistent. Under the Third Package interconnectors are TSOs but are treated as " <i>quasi generation</i> " for GB Capacity Market participation purposes.	Interconnection participation increases competition in the CM with potential benefits to GB consumers through a lower clearing price. We recognise that this is intended to be a short term solution, but it could lead to inefficient GB plant closures if de-rating of interconnectors is too optimistic and leads to under procurement (or structural over-supply in GB electricity market if derating is too pessimistic).	Interconnectors need to be regulated consistently across European and GB frameworks. Lobby DECC to move away from direct participation of interconnector owners in the CM to cross border participation by capacity providers as soon practicable De-rating of interconnectors within the Capacity Market should not be overly optimistic nor overly pessimistic.

6. Balancing Services Use of system

The BSUoS charge recovers the cost of day to day operation of the transmission system. BSUoS charges are dependent on the system management actions that National Grid System Operator takes each day in order to balance the system. Costs recovered through BSUoS charges include:

- Balancing mechanism actions (Bids/Offer acceptances) regardless of the reason for action;
- Trading costs;
- Option contracts;
- Short Term Operating Reserve (STOR) availability costs;
- Frequency response and reserve contracts; Supplemental Balancing Reserve (SBR) & Demand Side Balancing Reserve (DSBR) costs (testing & utilisation);
- Internal System Operator Costs (staff, systems, etc.); and
- System Operator Incentive Scheme receipts/payments.

BSUoS is set as an ex post charge, on a half-hourly basis. National Grid provides a monthly forecast of BSUoS as part of the current Monthly Balancing Services Summary (MBSS) report and publishes historical charges. However, BSUoS charges are hard to predict and the forecasts provided by National Grid are rarely correct.

BSUoS costs are recovered on a half-hourly basis from both generation and demand (split 50:50) on the basis of metered volumes. BSUoS charges are billed on Settlement Final (SF) data and reconciled on Final Reconciliation Volume (FRV) data. Generators and suppliers are liable for these charges, which are calculated daily as a flat tariff for each settlement period across all users.

The Connect and Manage policy contributes to the increased cost of managing the system due to sites being constrained off the system. The growth of embedded generation is also reducing the BSUoS charging base. We note however, once planned upgrades to the network are complete the expectation is that the costs associated with constraint management should reduce significantly.

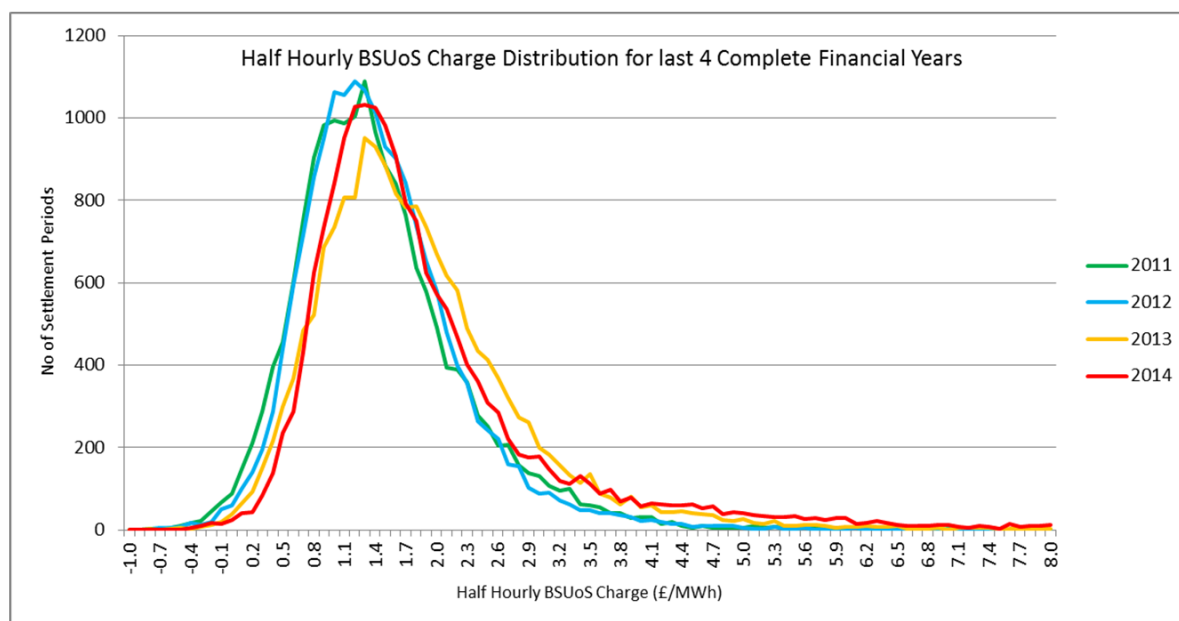
BSUoS charges are paid by generators and suppliers, interconnectors have been exempt since 28 August 2012, following the implementation of BSC change proposal P202.

Charges are apportioned on a half hourly £/MWh basis and applied proportionally according to a generator/demand portfolio share. There are two stages to financial settlement; SF and Reconciliation Final (RF). Interim initial – settlement Day +5. Daily, settlement Day + 16. RF + 14 months.

BSUoS is calculated ex-post with the charge published 5 days after the HH period in question, this makes it incredibly difficult to predict and therefore does not provide a useful price signal in terms of responding to the needs of the system. There is therefore an argument that BSUoS should be managed by the application of a fixed charge which should be more easily forecast with any under/over recovery applied at a later date. The graph below (Figure 6) shows the large volatility in BSUoS charges with considerable low-incidence, high-impact tail risk.

Figure 6 – Half Hourly BSUoS Charge Distribution curves for Last 4 Complete Financial Years

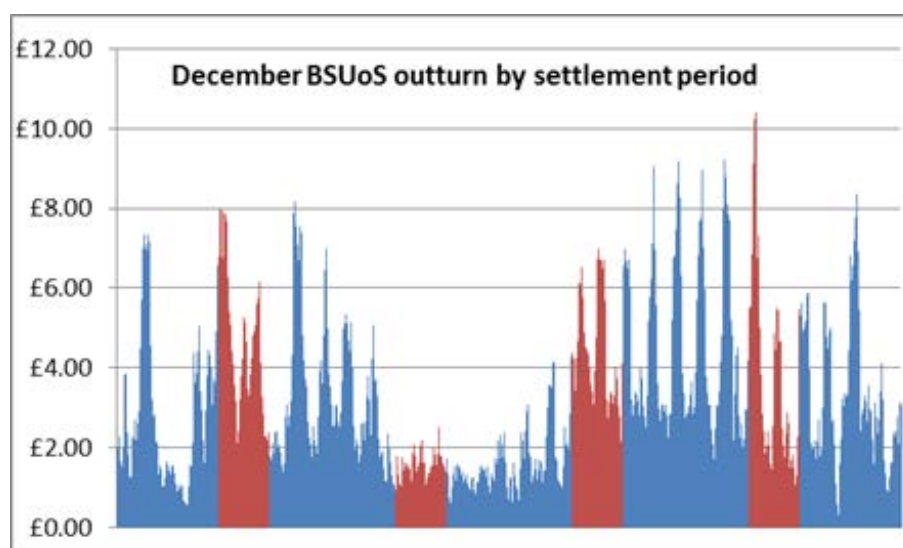
HH BSUoS Charge Distribution Curves (FY 2011 – FY 2014)



Upper range of half hourly BSUoS charges has been trimmed to £8.00/MWh to improve visibility of distribution curves.

The graph below also shows BSUoS volatility over December 2015 (non-weekdays in red).

Figure 7 – December 2015 BSUoS Outturn by Settlement Period



CMP250 is currently progressing through the workgroup stage of the change proposal process and aims to stabilise BSUoS by setting the charge with at least a 12 month notification period with over/under recovery taken account of in subsequent charging years. CMP201 was raised in December 2011 and proposed that generators become exempt from BSUoS charges, and National Grid recover 100% of the costs associated with its System Operation balancing activities from demand, i.e. GB suppliers. This was rejected by the authority in October 2014. CMP201 Removal of Balancing Services Use of System (BSUoS) charges from generation¹⁴ was rejected by the Authority in 2014 which would have changed the G:D split for BSUoS from 50:50 to 0:100 respectively.

It's also worth noting that CMP262 has also been raised and is progressing through the CUSC modification process. This modification looks to removal of SBR DSBP from BSUoS and moving it into a Demand Security Charge which would be paid for by demand only.

When looking to apply charges to other types of generators it is important to note that all renewable support mechanisms have been priced based on assumptions around other benefits received, including embedded benefits, and the removal of these would require a review of the prices paid for such energy. There are also proposals to discount a "system integration" charge from future Contracts for Difference (CfD) strike prices. These factors should all be reviewed if any work is done to apply BSUoS to all DG.

Issue	Impact	Recommendation
The range of products which now make up BSUoS charges has expanded with many products performing different functions and providing different signals for example black start.	BSUoS charges may no longer be representative with some products not used solely to balance the system.	National Grid should conduct a full review of the range of components contributing to BSUoS charges.
BSUoS is calculated ex-post with the charge only appearing 5 days after the HH, this makes it incredibly hard to predict.	BSUoS does not provide a useful price signal to allow all generators to respond to the needs of the system.	In conjunction with the above recommended review of what products should be included in BSUoS Ofgem should: <ul style="list-style-type: none"> ➤ To remove the risk of BSUoS variability Ofgem should review the

¹⁴ [CMP201](#)

		<p>composition and purpose of BSUoS, identify where generation/demand have the ability to respond to various elements of BSUoS.</p> <p>These elements can then be separated into fixed and variable charges which contribute to the overall BSUoS charge.</p> <p>➤ Once CMP250¹⁵ has been submitted to Ofgem for determination, Ofgem should consider this in conjunction with the above point.</p>
BSUoS is only paid by transmission connected generation and demand users (50%/50%). Distribution connected generation does not pay for BSUoS although arguably it benefits from a stable electricity network.	The avoided cost of distribution connected generation may cause a distortion in charging arrangements especially where Distribution connected Generation provide services to the System Operator.	Ofgem should consider whether Distributed Generators which cause system costs should contribute towards the costs of balancing the network.

7. Distribution connected generation

Distribution connected generation is subject to three types of distribution charges: connection charges, Distribution Use of System (DUoS) charges and the cost of green policies. The costs and the charging base used to recover these costs are reviewed below.

Distribution Use of System Charges

Distribution Use of System (DUoS) Charges recover the cost of installing and maintaining the shared distribution system assets that cannot be attributed to a single user in England, Wales or Scotland. Duos also recovers the cost of shared assets and maintaining and replacing sole use assets that are not recovered in the connection charge. There are two charging methodologies used by DNOs. These are the:

- Common Distribution Charging Methodology (CDCM) used by all GB DNOs to calculate DUoS tariffs for Low Voltage (LV) & High Voltage (HV) demand and generation connections. This is laid out in Schedule 16 of the Distribution and Connection Use of System Agreement (DCUSA). In CDCM, exporting LV and HV connected generators are deemed to provide beneficial support to the DNO networks and thus DUoS credits are paid by the DNO in recognition of this. The CDCM is the basis of a range of standard demand and generation tariffs in each DNO area and these have no locational or site-specific elements.
- Extra High Voltage (EHV) connections metered at 220kV or above or High Voltage connections which are metered at EHV/HV substations are subject to the EHV Distribution Charging Methodology (EDCM). This is laid out in Schedules 17 and 18 of the (DCUSA). EDCM DUoS charges are calculated on an individual site-specific locational basis. Generation connections deemed to provide beneficial support to the DNO networks may qualify for DUoS credit payments. As a transitional arrangement when export DUoS charges were introduced, Ofgem directed that generators which had connections established under 'pre-2005' contractual arrangements could be exempt from export charges for a 25 year period from connection. Currently therefore, a proportion of embedded generation in the EDCM category is not subject to export DUoS charging.

¹⁵ CMP250 'Stabilising BSUoS with at least a twelve month notice period'

The recoverable price controlled target revenue comprises Base revenues, Pass-through items, Incentive outcomes and RPI. The 'pot' of money is recovered across all customers with allocation based on licence objectives – predominately:

- Cost reflectivity;
- Facilitating competition; and
- Encouraging development of an efficient network

The EDCM was reviewed in 2015¹⁶ and proposed the following recommendations:

- That 'Charge 1' which sets charges based on future reinforcements is removed;
- That a single EDCM methodology should be considered based on Network Use Factors (NUFs) for setting locational charges. This should include an assessment of ways of reducing volatility and also allocating some of the NUF charges to unit rates and whether or not this would be compatible with Time of Use (ToU) or real time charging;
- That arrangements similar to those used in the CDCM (Time of Day (ToD) or Seasonal Time of Day (SToD)) should be considered to reduce the risk of inappropriate wholesale shifts of demand between time periods. Moving to unit based charging could cause greater instability in DNO income recovery, so the spread of any time bands should also be considered carefully;
- That the allocation of costs should be reviewed so as to allocate these as closely as possible to the Group of customers which benefit from them or historically caused them;
- That ways of making available the EDCM models should be investigated so that, to the greatest extent possible, the basis of charges is transparent to customers. But the EDCM model also needs to satisfy customer confidentiality requirements.
- That, as an alternative to the above, development of a new, all-encompassing methodology, to replace both the EDCM and CDCM should be considered; and
- That development of any new, all-encompassing methodology should include consideration of options for generation credits, as small generators in the CDCM currently receive credits regardless of whether they are intermittent or non-intermittent and embedded generators benefit by a reduction in their demand charges

A 'minded-to' response on the recommendations noted above is currently being considered Ofgem.

Tariff structure

For Non-Half Hourly and aggregated HH metered sites (domestic and business)

- Fixed charge – p/day
- Unit charges – p/kWh
 - Time bands determined by meter configuration or set by the DNO for aggregated HH

For Half Hourly metered sites

- Fixed charge – p/day
- Capacity charge – p/kVA/day
- Unit charges – p/kWh
 - Time bands set by each DNO
 - The CDCM has three time bands – TOD
 - The EDCM – One 'super red' time band – STOD

For HH metered non-intermittent generation sites the three time bands act as the equivalent of a Triad signal with a peak rate to incentivise generation at time of system peak and theoretically reduce the need to reinforce the distribution network. Intermittent generation sites only have one unit rate applied as the output is not seen as controllable. The charges for the demand tariffs, Time of Day (Green, Amber and Red) are set to mirror the impact on the distribution network. These time bands are set by

¹⁶

<http://www.energynetworks.org/assets/files/electricity/regulation/DCMF/EDCMReviewGroupFinalReport%2031Dec2015.pdf>

each DNO independently but tend to be set to similar periods as shown in the example below. We also note that HH sites also have reactive charging applied through DUoS.

Figure 8 - Example time band tariff for HH metered properties (Source: Western Power Distribution)

Time Bands for Half Hourly Metered Properties			
Time periods	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday	16:00 to 19:00	07:30 to 16:00 19:00 to 21:00	00:00 to 07:30 21:00 to 24:00
Weekends			00:00 to 24:00
Notes	All the above times are in UK Clock time		

The proximity of local generation to demand is recognised through the credits that are paid to distributed generation for offsetting the impact that a demand user would cause. This enables for example a manufacturing company with its own generation to receive lower overall charges due to the benefit of its output being used by local demand. This reiterates the point that the correct signals need to be provided.

The structure of the distribution tariffs has also been highlighted as being unclear and complex. The tariffs themselves include capacity and energy based charges and may involve additional charges such as for excess reactive capability. There are a large number of customer categories ranging from small domestic to larger demand customers connected at extra high voltage. It is therefore difficult to determine the cost reflectivity of the tariffs, how the allowed revenue is collected from embedded generation and demand, how a move to a DSO will impact the current methodology. In addition, there are issues with DNOs having different interpretations on some aspects of the charging methodology. This all makes it difficult to compare the tariffs across multiple DNO networks.

Issue	Impact	Recommendation
Whilst the CDCM is the same for all DNOs with the EDCM having two versions, this makes distribution charging methodologies complicated and inputs vary between DNOs. This makes comparing charges between DNOs difficult.	The CDCM is fully transparent with all models available DNO charging statements, EDCM also appear in charging statements. Customers, therefore, find comparison of charges (particularly EDCM) difficult due to lack of availability of the supporting models and difference across the six DNOs.	Ofgem should undertake a review of the CDCM with a view to streamlining the methodology and improving transparency. Ofgem should also ensure improved transparency of the EDCM and require publication of the EDCM models. Further work is required to ensure as much consistency and coordination of updates across all six DNOs to aid the process of comparison well ahead of new charging periods.
A review of the EDCM has been carried out to investigate the issues that have arisen since the implementation of the EDCM.	Several recommendations have been made to improve the EDCM.	Ofgem should progress the proposed remedies highlighted in the EDCM review.
Stability of charging especially for EHV metered sites is not robust and can vary significantly depending on whether more generation joins the network or demand leaves.	Uncertainty around future charging tariffs can have a significant impact on a developer's decision as to whether to build a power station.	Ofgem and DNO's should review long term forecasting of distribution network charges to consider where additional clarity can be given regarding future costs.

8. Connection charges

Connection charges recover the cost of user's connection to the network. Charges are set either as a one off at the time of connection or annually, in advance, directly from the cost of single user assets built for customers' connections.

The methodology for calculating the connection charge varies whether the connection is on the transmission or distribution network as well as the security that needs to be provided under "user commitment" obligations.

Connection charges are typically used to charge transmission system users for physical connection to the network. Broadly, there are two alternative approaches currently used to setting such charges:

- "Shallow" Connection Charges: These are usually based on simply recovering the costs related to the physical connection assets between the connected party and (usually) the nearest network connection point. This approach is used on the UK's transmission network.
- "Shallowish" Connection Charges: These are based on a combination of shallow charges plus an allocation of the costs related to any additional "downstream" network reinforcement required to support the load of the connected party. This approach is used on the UK's distribution network.
- Additionally there has previously been "Deep" Connection Charges: These are based on the full costs of supporting the load of the connected party.

Transmission Connection Charges

The Connection Use of System Code (CUSC) sets out the charges which need to be paid by user connected to the transmission network. For transmission connected generation a connection charge becomes liable if there are single user assets which are used to connect to the transmission network, these are typically transformers or parts of substations. Transmission connection charges are considered as "shallow" network connection charging, with many users paying no connection charge, but instead paying through TNUoS for their use of the system.

Charges are set ex ante with Users able to choose how to pay the connection charge

- Capital contributions – Paying for some or all of the capital cost at commissioning or during the life time of the asset;
- Annual connection charge, based on the outstanding gross asset value and net asset value of the asset; and
- Depreciation period of assets (usually 40 years)

Connect and manage

Since February 2011, Generation Customers on the transmission network are offered connection dates based on the time taken to complete a project's 'enabling works', i.e. ahead of the completion of any wider transmission system reinforcements required under the security standards. This does not apply to plant connecting to the distribution network where non-firm contracts do not compensate curtailment. Connecting generators ahead of the completion of wider works may result in additional constraints on the National Electricity Transmission System which are passed through to customers via BSUoS. Although connect and manage has enabled additional capacity to be built on the transmission network it has also increased costs to parties which pay BSUoS.

Conventional generation trying to connect to the transmission network using connect and manage have found that the needs case which is approved by the Transmission operator is too expensive to justify the connection due to the high constraint costs which would be created.

Distribution Connection charges

Connecting to the distribution network is becoming increasingly difficult as a result of unmanageable congestion as well as limited information available from DNOs regarding which part of the network and what size of connection is most cost efficient. As a part of the Quicker and More Efficient

Connection (QMEC) work that Ofgem is overseeing, the DG DNO Steering Group have taken steps to improve the connection regime. The hope is that these steps will provide a more accurate view of what projects will be coming online, make it easier to get distribution grid connected and prevent any unnecessary reinforcement to the transmission and distribution grid.

Some of the QMEC work that has appeared already includes DECC's consultation on the reintroduction of Upfront Assessment and Design Fees which was issued in March 2016. The proposal was to introduce Upfront Assessment and Design fees which will curb the amount of 'speculative applications' and therefore alleviate congestion and provide a more realistic view of connections. The ENA released a consultation in March 2016 on introducing milestones for a project with a connection offer; the intention being that developers have to demonstrate progress made towards bringing a project online by meeting a set of milestones. The ENA also released a consultation on the treatment of change to a connection application; this consultation focuses on what constitutes a material change to a connection offer and will help to queue manage.

As noted above, connecting to the distribution network can trigger reinforcement work to the transmission and distribution grid and for this reason, costs can be considered as "shallowish". QMEC should mean that only viable projects will receive and maintain a connection offer, which will provide a realistic view of the grid, and hopefully trigger less reinforcement to networks, bringing costs down. Costs associated with connection can vary significantly depending on the nature of the connection although there is competition in contestable works where an Independent Connection Provider can be appointed.

Some connection agreements may include profiled export restriction to enable connection at lowest cost, also known as non-firm agreements, but this is dependent on the DNO. Non-firm agreements or 'flexible connection agreements' are agreements whereby generators may be asked to stop generating at peak times. This type of agreement means that some distribution network reinforcement isn't required, but that generators may have an export limit applied to how much they can generate.

Issue	Impact	Recommendation
Distribution connection charges can vary considerably with the network only being reinforced once generation has committed to building	The distribution network is under developed with no strategic investment taking place which impacts the ability of generation to build projects.	We support Ofgem's work to allow alternative network investment to take place sooner and to free up un-used capacity in the connection queue. We support the adoption of more smart flexible connection terms allowing non-firm connections to progress.
Thermal generation trying to connect to the transmission network using connect and manage cannot always justify connection agreement due to the high probability and cost of being constrained off the network.	Thermal generation is not able to connect to the network using connect and manage, therefore, location signals are not being used to locate plant.	Ofgem should consider how strategic network investment can be progressed taking account of future network constraints.

9. Consideration of Cross-Code Interaction

This report highlights the complexity of the current charging regime with multiple codes operating under different governance structures – this places a significant burden on industry participants. Significant benefits in terms of transparency and cost saving could come from the simplification of codes. The challenge however is the amount of time and resource required to rationalise the codes. It is most likely to be cost and resource-efficient if delivered alongside other change programmes that

affect the codes. Such as the impending implementation of the EU Network Codes. Therefore, we consider that a clear vision of the optimal structure and number of industry codes should be developed as well as ensuring tariffs structures are easy visible.

A governance structure must be established which guarantees the careful consideration of the interactions between different codes, to ensure that a joined up approach to code changes as well as establishing the long term direction of code structures can be taken. This would deliver efficiencies in implementation, development and structure of the codes. This in turn could allow market participants to allocate staff more effectively, understand the direction of the code framework and better prepare for change. Any changes to the code governance framework should look to simplify the framework and increase accessibility for all market participants.

10. Capacity Market Supplier Levy

The Capacity Market has been designed to ensure that sufficient reliable capacity is in place to meet demand. It works by offering the opportunity for all capacity providers, new and existing power stations, electricity storage and capacity provided by demand side response that successfully bid into an auction to benefit from a steady, predictable revenue stream which may serve as a solid base for future investment decisions. The cost of the Capacity Market will be met by consumers via a levy charged to electricity suppliers on a Net basis.

The current system design has the potential for embedded generators to receive a significant 'double benefit' through the Capacity Market supplier levy. Current arrangements provide an incentive to suppliers to seek agreements with embedded generators in order to reduce their Capacity Market levy payments. This is done via the 'net' calculation of the supplier levy, which means that embedded generation can be used to reduce a supplier's share of the 4-7pm winter peak share a competitive markets should result in the value of these embedded benefits being paid to the embedded generator as part of Power Purchase Agreement (PPA) contracts. PPAs may include a discount to the full value to take account of transaction cost and risks faced by the offtaker. The full value that is passed through by suppliers is largely unknown and will vary for each supplier. Also, contracting directly with National Grid will allow the full value of the embedded benefits to be paid to the generator.

The CM supplier levy being recovered through net charging means that embedded generators can access support while also avoiding the levy for a supplier. The supplier levy arrangements could increase costs for domestic customers because the total cost of the CM scheme will remain the same, so whilst some suppliers will reduce their peak share, other suppliers and customers' peak share will increase. In addition, suppliers also have to collect from customers the value of the CM avoidance premiums which they have paid to generators. This further increases costs for the consumers each supply.

One solution to this issue could be to amend the Electricity Capacity Regulations and base the supplier levy on 'gross' demand, rather than 'net'. This need not necessarily detract from turn-down demand side response and time-of-use tariffs. If a customer avoids using electricity between 4pm-7pm (or you could link this to when margins are tight) in the winter this can help the relevant supplier to reduce its levy. It would appear justifiable for this to be rewarded. However, rewarding embedded generators for assisting the avoidance of levy payments has the perverse outcome of raising levy costs for other users, whilst potentially displacing more efficient transmission generation.

However, we also note that recovering the CM Supplier Levy on a Gross basis would likely lead to an increase on the clearing price of the capacity market which is paid to all generators who are successful in the auction through the elimination of typically price taking smaller generation. Behind the meter generation and Demand Side Response will also have to be addressed as these can also avoid charges even if the levy was recovered on a gross basis. DECC was clear when setting out the cost recovery mechanism of the CM Supplier Levy that this would be charged on a net basis. It is, therefore, not unreasonable to presume that embedded generation could make financial investment decisions based on DECCs policy when it was put in place. Changes to policy where financial investment decisions have been made could increase costs of capital for a wider range of energy projects reflecting increased regulatory and political risk.

The Supplier Levy is currently charged by suppliers to consumers based on their imported kWh in any given half hour. Certain elements of the Supplier Levy have differences in how they are calculated and passed onto Suppliers and it remains to be seen how Suppliers will then pass on these costs to their consumer base.

Issue	Impact	Recommendation
The Capacity Market Supplier Levy is calculated on a net basis.	Distributed Generation (DG) is paid to avoid the cost of the CM applied to customers creating a double benefit for DG.	Energy UK recommends that the CM Supplier Levy be applied on a gross basis in the future in the same way that the CfD Supplier Obligation is applied. DECC has confirmed that it intend to do this in time for the 2017/18 delivery year. Behind the meter generation and Demand Side Response will also have to be addressed as these can also avoid charges even if the levy was recovered on a gross basis.

11. Policy costs

Embedded generation and storage, sitting within the grid supply points is exposed on its import of energy from the Grid to the attribution of supplier charges including FiT, RO, CfD, CM and AAHEDC. Due to the growing rollout of renewables and other forms of subsidised generation and the introduction of the capacity market, policy costs are expected to grow significantly over the short term¹⁷.

It is important to highlight this is a charge that transmission connected generation does not pay on any imported energy or installed capacity. This represents a benefit to a Transmission connected generation over a distributed connected generator. This cost difference is relevant when reviewing the CM element of the Supplier Levy as an embedded generator will have to contract with a supplier in order to potentially benefit from a supplier avoiding the CM element of the Supplier Levy and in doing so will have to pay all other elements of the Supplier Levy as a result.

Issue	Impact	Recommendation
Embedded generation, sitting within the grid supply points is exposed on its import of energy from the Grid to the attribution of supplier charges (principally FiT, RO, CfD, CM and AAHEDC)	DG face costs which transmission connected generation are not.	DG should be exempt from supplier charges in the same way transmission connected generation is.

12. Retail

There are now over 30 suppliers in the GB retail energy market, and these companies compete with each other to drive down the end costs of their products to win new customers.

Because of this, suppliers have the incentive to pass through fixed costs associated with energy supply in the most efficient way possible. Although how cost are recovered is ultimately a commercial decision for suppliers. There will, therefore, be different methods of reflecting costs.

¹⁷ https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/384408/Prices_and_Bills_Annex.xlsx

Sufficient lead time prior to any changes taking affect is also important as many suppliers will have fixed contracts with customers in place for a period of 12 – 36 months as well as needing sufficient time to make changes to IT systems.

13. Engagement Across Other Energy UK Committees

Following feedback from the Energy UK Board, engagement on the issues covered in this paper was sought from the other committees within Energy UK – the Retail Committee, New Energy Services & Heat Committee (NESH), and the Strategic Policy Committee. This was carried out to ensure that the report reflected the full breadth of stakeholder interests.

Retail Committee Views

Representatives from the Retail Committee were supportive of the emphasis that changes to the charging regime must focus on the need to deliver a sustainable and secure energy system at least cost to the consumer over the long term. The issue of ‘fairness’ was highlighted as important. It is necessary to strike a careful balance between the delivery of a fully cost-reflective system, and the need to deliver a fair energy system which benefits the end consumer. For example, domestic consumers who live on the far reaches of the distribution network impose costs upon the network. However it would be inappropriate to charge these consumers the full cost-reflective price for their connection to the distribution network. To do so would often be financially unviable for such consumers and risk driving them towards a less efficient, islanded arrangement. Issues of ‘fairness’ are also particularly significant for development of any future arrangements that require considerable levels of consumer engagement in order to benefit from. For example, the introduction of time of use tariff structures, while beneficial both to the system and to engaged consumers, risk shifting significant costs on those consumer that are unable to engage fully with the retail market. Such issues significantly affect domestic consumers on low-incomes, or who are otherwise vulnerable.

Sufficient lead time prior to any changes taking affect is also important as many suppliers will have fixed contracts with customers in place for a period of 12 – 36 months as well as needing sufficient time to make changes to IT systems.

New Energy Services & Heat (NESH)

One of the issues of most significant concern to the representatives of the NESH committee was that of electricity storage. It is essential that any changes to the charging regime should be mindful of the need to develop electricity storage as an essential part of the transition to a least-cost, sustainable and secure energy system. To this end, a level playing field must be created for electricity storage. This does not mean treating storage identically to either demand or generation (as it is neither), but creating a new classification for storage that enables it to compete on an equal basis.

The demand-side flexibility options offered by new forms of low-carbon heating were also explored. It is clear that the installation of individual or large-scale heat pumps, coupled with thermal storage, could offer turn-up and turn-down DSR potential. Such benefits are further extended by deployment of ambitious levels of energy efficiency. Deployment of smart technologies such as DSR-enabled heat pumps can be highly supportive of the transition to a least-cost, secure, sustainable energy system. Any changes to the charging regime must not prevent development of new technologies and business practices such as increased use of DSR or storage.

Strategic Policy Committee

Representatives from the Strategic Policy Committee were highly supportive of the underlying values of this charging paper:

- Cost reflectivity
- Locational signals
- Market signals
- Stability and predictability
- Long term outlook
- Harmonisation with Europe

➤ Transparency

These were considered appropriate to be used as guiding principles when setting policies to deliver the transition to a sustainable, secure energy system at least cost. It was envisaged that such a system would include a significantly greater role for a wide variety of renewable technologies, smarter energy networks, new and greater applications of demand side response, a significant roll out of electricity storage, and greater efficiency delivered both through passive energy efficiency technologies (such as insulation) and active solutions delivered through the internet of things (such as smart thermostats).

Any changes to the charging regime must be written with the need for such a transition in mind and therefore not create barriers to entry or expansion for new and innovative participants in the energy system.

14. Value of the embedded benefit

Whilst the exact extent of embedded benefit compared to transmission connected generation depends on a number of factors including location, the table below gives a reasonable estimation of the potential benefits based on available data. This is independent of the generation type and its efficiency and highlights the differences in how transmission and distribution connected capacity is charged and rewarded.

Charging	Sub Category	Unit	Distribution Connected (Conventional)		Distribution Connected (Intermittent plant)		Transmission Connected (Conventional)		Transmission Connected (onshore)		Transmission Connected (offshore)	
De-rating Factor			80%		40%		80%		40%		40%	
Capacity		MW	99		99		100		100		100	
			Low	High	Low	High	Low	High	Low	High	Low	High
TNUoS Generation	Wider Tariffs	£m					-0.26	2.02	-0.40	1.85	-0.40	1.85
	Small Generator Discount ¹⁸	£m					-1.15	0.00	-1.15	0.00	-1.15	0.00
	Substation Payment	£m							0.00	0.05		
	Local Circuits	£m							-0.11	0.62	-0.11	0.62
	Local Offshore tariffs	£m									3.31	6.72
TNUoS Demand	Demand Tariffs - HH	£m	-3.98	-5.14								
DUoS (G-DUOS pre/post 2005)		£m	0.10	0.10	0.10	0.10						
BSUoS		£m					1.56	1.56	0.78	0.78	0.78	0.78
Green policy costs		£m	0.10	0.13	0.10	0.13						
Connections		£m	0.01	9.01	0.01	9.01	0.00	1.37	0.00	1.37	0.00	1.37
Assistance for Areas with High Electricity Distribution Costs		£m	-0.16	-0.16	-0.08	-0.08						
CM Supplier Levy Avoidance (2016/17)		£m	-0.03	-0.03								
CM Supplier Levy Avoidance (2017/18 Delivery Year)		£m	-2.31	-2.31								
Total		£m	-6.27	1.60	0.13	9.16	0.15	4.95	-0.88	4.67	2.43	11.34

CM Supplier Levy Avoidance if DECC move to a Gross charging methodology		£m	0.00	0.00								
Total without CM Supplier Levy Avoidance		£m	-3.93	3.94	0.13	9.16	0.15	4.95	-0.88	4.67	2.43	11.34

Table produced by Energy UK using publically available data:

Data is given for 2016/17 where available. In some instances, this has not been possible, for instance connection charges are taken from the 2014 embedded benefits review.

TNUoS Tariff Forecasts – Forecast from 2017/18 to 2020/21 (Jan 2015) (<http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/>)

National Grid Open Letter - Review of the embedded (distributed) generation benefit arising from transmission charges (April 2014)

National Grid - Review of the Embedded (Distributed) Generation Benefit arising from transmission charges (2014)

National Grid Charging Statement Assistance for Areas with High Electricity Distribution Costs Scheme - Effective from 1 April 2015

Small generators in Scotland connected at 132kV currently receive a discount to TNUoS charges. Any sub-100MW offshore generation projects connected at 132kV will be covered by the small generator discount

Methodology

Range gives the extremes dependent on technology type and charging / support available. Tariffs are taken from publically available information as per sources above. Connection charges are taken from National grid, but substantiated with member data. Average transmission connection charges are £2.62/kW (range £0 - £13.73), and average distribution connection charge is £15.03/kW (range £0.11 - £90.97)

Glossary

Acronym	Definition
AAHEDC	Areas with High Electricity Distribution Costs
BSUoS	Balancing Services Use of System
CATO	Competitively Appointed Transmission Owners
CDCM	Common Distribution Charging Methodology
CfD	Contracts for Difference
CM	Capacity Market
CMSL	Capacity Market Supplier Levy
CUSC	Connection and Use of System Code
D	Demand
DC	Direct Current
DCM	Distribution Charging Methodology
DCUSA	Distribution and Connection Use of System Agreement
DECC	Department of Energy and Climate Change
DG	Distributed Generation
DNOs	Distribution Network Operator
DSOs	Distribution System Operators
DUoS	Distribution Use of System
DSBR	Demand Side Balancing Reserve
EDCM	Electricity Distribution Charging Methodology
EHV	Extra High Voltage
ENA	Energy Networks Association
ENTSO	European Network of Transmission System Operators
FiT	Feed in Tariff
FRV	Final Reconciliation Volume
G	Generation
GSPs	Grid Supply Points
HH	Half Hour (demand tariffs)
HV	High Voltage
MBSS	Monthly Balancing Services Summary
MITs	Main Integrated Transmission System
NGET	National Grid Electricity Transmission
NUFs	Network Use Factors
OFTOs	Offshore Transmission Owners
PPA	Power Purchase Agreement
RF	Reconciliation Final
RO	Renewable Obligation
SBR	Supplemental Balancing Reserve
SF	Settlement Final
SHET	Scottish Hydro Electric Transmission
SPT	Scottish Power Transmission
STOR	Short Term Operating Reserve
SToD	Seasonal Time of Day
TOs	Transmission Operators
ToU	Time of Use
TNUoS	Transmission Network Use of System

List of members who participated in the Working Group

Name	Company	Name	Company
Tim Collins	Centrica	Graz Macdonald	Green Frog Power
Aled Moses	Dong Energy	Karl Maryon	Haven Power
Cem Suleyman	Drax Power	Paul Wakeley	National Grid
Joseph Underwood	Drax Power	Jeremy Sainsbury	Natural Power
Stuart Cotton	Drax Power	Phil Ballard	Opus Energy
Brian Tilley	E.ON	Peter Williams	Pöyry
Steve Davies	E.ON	David Cox	Pöyry
Paul Jones	Uniper	Graham Pannell	RES
Jack Abbott	EDF Energy	Raoul Thulin	RWE Npower
Mari Toda	EDF Energy	Bill Reed	RWE Npower
Paul Mott	EDF Energy	James Anderson	Scottish Power
Guy Buckenham	EDF Energy	Colin Prestwich	Smartest Energy
Simon Lord	ENGIE	Polina Kharchenko	SSE
Siobhan McAdam	ESB	Dan Saker	SSE
Jeremy Guard	First Utility	Pavel Miller	SSE
Alan Goodbrook	Good Energy	Garth Graham	SSE
Tom Steward	Good Energy	John Tindal	SSE
Guy Philips	Uniper	Kirsten Gardner	Stag Energy
Mary Teuton	VPI Immingham	Elizabeth Adams	UK Power Reserve
Lisa Waters	Waters Wye	Sam Wither	UK Power Reserve
Rachel Evans	Welsh Power	Lizzie Adams	UK Power Reserve
Matthew Tucker	Welsh Power	Oliver Day	UKPN