ofgem

Making a positive difference
for energy consumers

To all interested stakeholders

Date: 29 July 2016

Open letter: Charging arrangements for embedded generation

As indicated in our Forward Work Programme[1], we have been reviewing the transmission network charging arrangements for embedded generators since January 2016. The DECC[2] Capacity Market (CM) consultation[3] referred to our concerns that the charging arrangements for embedded generators ('embedded benefits') may over-reward embedded generation, which could be having an increasing impact on the energy system, by potentially distorting investment decisions and leading to inefficient outcomes in the CM. Responses to DECC's consultation indicated that many market participants shared these concerns regarding the potential for over-reward of embedded generation.

As explained further below, we anticipate that we will be required to consider at least two CUSC[4] modification proposals relating to embedded benefits later in 2016. Given what we consider to be the importance of embedded benefits issues and the priority that we attach to these issues, we wish to place ourselves in the best possible position to be able to take a robust decision on those proposals (and any alternatives) as soon as possible. With this aim in mind, this open letter sets out our current thinking in relation to embedded benefits, and invites early input to the development of our thinking in this area. We would emphasise that this letter sets out our initial views in order to provide a sensible framework and structure for the inputs sought. We have not reached any decision on the appropriate future treatment of embedded benefits nor how we should view possible modification proposals; it would not be appropriate to do so in advance of receiving any relevant modification proposals. We are therefore keen to hear all views in respect of the issues raised with responses to the letter requested by 23 September 2016 (see below for more details).

1. Background

We have had concerns about the transmission charging arrangements for embedded generation (EG) for a number of years[5]. In particular, we are concerned that these arrangements are preventing a level playing field between sub-100MW EG on one hand and larger (over-100MW) EG and transmission connected generation (TG) on the other. Several attempts to develop enduring charging arrangements for EG were postponed due to other priority work in access and charging, such as the Transmission Access Review[6] and Project

[1] https://www.ofgem.gov.uk/system/files/docs/2016/03/forward_work_programme_2016-17.pdf
[2] DECC has now been replaced by BEIS (Department for Business, Energy and Industry Strategy)
[3]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/504217/March_2016_Consultation_Document.pdf
[4] Connection and Use of System Code (CUSC)
[5] Examples of documents where embedded benefits are discussed is 30 July 2007, Transmission Arrangements for Distributed Generation - Working Group Report and Next Steps and 23 January 2009, Conclusions in respect of the consultation on the discount for small transmission connected generators from 1 June 2009
[6]http://webarchive.nationalarchives.gov.uk/20130402174434/http://www.ofgem.gov.uk/Networks/Trans/Archive/ElecTrans/TADG/Documents1/Small%20Generators.pdf

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

TransmiT[7]. However, we consider that the increasing scale of these benefits available to sub-100MW EG that are not available to over-100MW EG and TG, and the potential impact of these arrangements on the development of the energy market, mean that this needs to be addressed as a matter of priority.

Our energy system is changing rapidly. The growth of intermittent generation and smarter technology will lead to more flexible generation connecting and providing important services to the system. In this increasingly flexible and changing environment, it is important to ensure a level playing field so that developments lead to as efficient an outcome as possible. It is with this in mind that we have been thinking about charging arrangements for EG.

A number of BSC[8] and CUSC code modifications and alternatives have been raised and are now being developed. These modifications will come to us for decision later this year. Each proposal will be considered on its merits and in the light of the information available at that time. We recognise that the changes proposed will affect a number of factors including cost reflectivity, competition, security of supply and consumer bills. We will continue to consider these as more information becomes available.

We consider that there is value to market participants in setting out what we see as the key issues at this stage based on the information we have now, because these arrangements are both complex and important. Any feedback provided will be considered and will help to further develop our thinking and allow us to address any CUSC modification proposals that come before us more quickly and efficiently than otherwise. We welcome any early input and your views on this open letter, in parallel with engagement in the ongoing modification process which is considering changes to these arrangements.

2. Transmission charging arrangements for sub-100MW EG – embedded benefit

Transmission network charges comprise Transmission Network Use of System charges (TNUoS) which recover the cost of providing and maintaining transmission network assets and Balancing Services Use of System (BSUoS) charges which recover the cost of system operation[9]. Both TNUoS and BSUoS are levied partly on generation and partly on demand.

TNUoS charges for both demand and generation consist of two elements:

- locational signal – this is a forward-looking locational signal that should broadly reflect the costs and benefits of EG and TG on the transmission system in different locations; and
- residual[10] – this element is used to recover the remaining costs of the transmission network, which are largely fixed and sunk costs, as well as some additional costs such as network innovation funding.

BSUoS charges allocate 50% of the cost of operating the transmission system to demand and 50% to generation. BSUoS is largely a cost recovery mechanism: costs are allocated to the half hour in which they occur, but not to specific network users that drive costs and there is no locational signal.

The approach for transmission charging for generation has been only to charge generators directly connected to the transmission network and over-100MW EG.

The approach to allocating transmission charges (both TNUoS and BSUoS) among demand-side users has been based on net demand in a Grid Supply Point (GSP) Group[11] (which is gross or total customer demand on the distribution network less any generation output

[7] http://www.nationalgrid.com/NR/rdonlyres/44201E6D-B4A1-4D94-BF50-342350ED3D69/43170/IndustryLetter_final_review.pdf
[8] Balancing and Settlement Code (BSC)
[9] Please note that transmission losses are also considered to be a transmission charge. We have not explicitly considered transmission losses here
[10] The residual element is aimed at recovering the required total revenue as well as achieving a pre-defined ratio between the TNUoS charges recovered from demand and generation. Currently this predefined ratio is aimed at limiting generation tariffs to on average €2.50/MWh
[11] A GSP Group is a group of Grid Supply Points that make up a local distribution system

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

from sub-100MW generators embedded on the distribution network within each GSP Group).

TNUoS demand charges are allocated to suppliers on the basis of their average net demand over the triad periods – these are the three half-hour periods of highest system net demand during the period November to February, separated by 10 days.

Unlike over-100MW EG, sub-100MW EG is treated as negative demand. Suppliers can, therefore, use sub-100MW EG to reduce their net demand and so the level of TNUoS demand charges for which they are liable. Suppliers tend to share a significant part of these avoided TNUoS demand charges with EG by making payments to EG. One part of these payments is related to the TNUoS demand residual which this document refers to as "TNUoS demand residual payments". We note that some of this sub-100MW EG is located behind the meter[12], which means the output from these generators is not metered directly.

The embedded benefits we have identified include both the payments that EG can receive for helping suppliers to avoid transmission demand charges and the avoided transmission generation charges that sub-100MW EG does not pay[13].

The table below sets out the elements of embedded benefits relating to transmission charging that we consider in this letter.

Table 1: Embedded Benefits related to transmission charges

Transmission charge element	What is it? High level summary	Current value of charge element
TNUoS demand locational signal	Currently EG that generates at triad (mainly non intermittent EG) is treated as negative demand and hence face the inverse of the demand locational signal. This is roughly the equivalent of the generation signal. The differences between the two signals are: • the difference in charging bases, triad vs TEC, • different treatment of intermittent/non-intermittent, and • different zonal differentiation (27 generation zones vs 14 GSP Groups).	Varies by region £-5.09/kW to £6.54/kW
TNUoS demand residual	This is the majority of embedded benefit. Sub-100MW EG that generates at triad (mainly controllable generation) will be able to receive payments from suppliers related to this element of the TNUoS charge.	c£45/kW
TNUoS generation locational signal	EG does not pay this locational charge. However, the negative TNUoS demand locational charge is roughly equivalent (see above)	Varies by region and technology £-6.91/kW to £19.14/kW
TNUoS generation residual	EG currently does not pay the TNUoS generation residual.	c£0.5/kW
BSUoS demand charge	The BSUoS demand charge is based on a supplier's net consumption at the GSP Group, therefore sub-100MW EG can offset demand and receive payments for reducing the BSUoS bill for that supplier. This, along with the BSUoS generation charge, applies to EG that generates. Both elements will be more significant for higher load factor EG.	c£2/MWh

[12] Installation behind the meter is installation which has no network access arrangement to export to the grid. All energy produced net of consumption is spilled.
[13] We note that BEIS is currently consulting on whether to change the recovery basis for the CM supplier levy from a gross to a net demand charging basis, but we do not consider this matter in this letter

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

BSUoS generation charge	EG currently does not pay the BSUoS generation charge	c£2/MWh

We are concerned that the elements in the table above are preventing a level playing-field between sub-100MW generation connected at distribution level and all other generation. We discuss each element below.

We have not considered Residual Cashflow Reallocation Cashflow (RCRC) and Areas of Assistance (AAHDC) in any detail since they are low in value and hence unlikely to be causing major distortions. Further, we have not considered transmission losses since the CMA proposals for locational transmission losses will remove the losses-related embedded benefit.

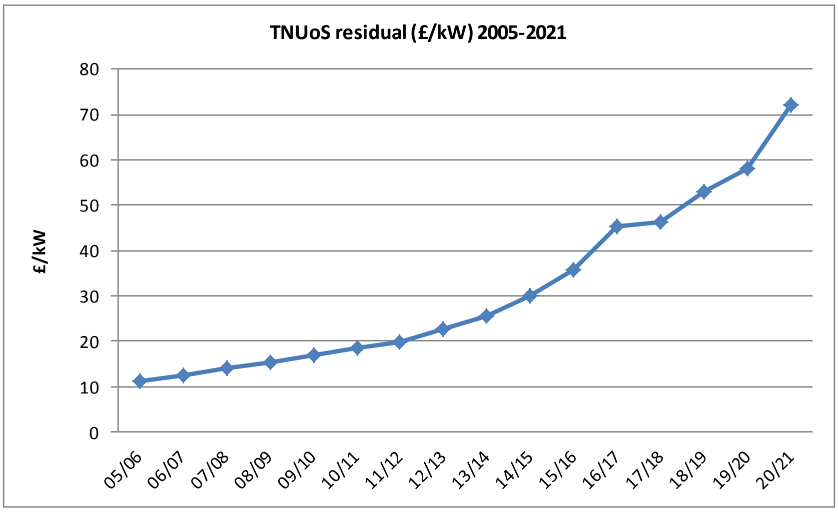
3. Impact of TNUoS and BSUoS embedded benefit

As mentioned above, the TNUoS demand charges include both a forward-looking locational signal and a cost recovery element, the residual. The BSUoS demand charge is a cost recovery charge only. EG can receive payments for helping suppliers reduce their demand transmission charges including reducing their contributions towards fixed/sunk cost recovery. The connection of an increasing amount of sub-100MW EG to the distribution system logically cannot help to avoid sunk/fixed costs of developing and maintaining the transmission network. The payments to EG are an extra cost to suppliers over and above the payment of transmission charges to National Grid, and therefore an additional cost to consumers, to the extent that this cost is passed on to consumers.

We are concerned therefore that the current level of embedded benefits may not reflect the actual benefits that sub-100MW EG provide to the transmission system and increase costs for consumers. We are particularly concerned about TNUoS demand residual payments which account for the majority of the embedded benefit and are forecast to increase significantly. We think that this element currently may be leading to the biggest distortions and that therefore there may be grounds to make changes to the charging arrangements in this area as a priority. We think that changes to how TNUoS demand residual charges are allocated among suppliers would create a more level playing field between sub-100MW EG and other generation. The evidence we have seen so far suggests that there are likely to be significant net benefits to consumers to changing these arrangements.

3.1 Our main concern – the TNUoS demand residual

In the past, when the value of the total transmission charges was lower, the proportion of transmission charges allocated to suppliers was lower and the amount of sub-100MW EG more limited, the impacts of supplier payments to EG relating to the TNUoS demand residual were also smaller and did not give rise to such a major concern. However this is no longer the case as shown in the graph below.



The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

With the increase in overall TNUoS charges and the rapid increase in the volume of EG[14], the size of TNUoS demand residual payments has grown as has the number of parties receiving them. This creates a large benefit to connecting to the distribution network rather than the transmission network.

We are concerned that the size and increase of the TNUoS demand residual payments may now be distorting the market by:

- leading to an inefficient mix of generation by encouraging investment in smaller distribution connected generation (which can take advantage of the embedded benefits revenue stream) over potentially more efficient larger transmission connected generators (TG) or over-100MW EG (which do not have that revenue stream);
- leading to TG exiting because it cannot compete;
- distorting dispatch by dampening prices at peak times when EG dispatch out of merit[15] to generate in the triad periods;
- distorting the outcome of the capacity market (CM) by holding down prices since smaller EG can bid in at significantly lower prices than larger EG and TG; and
- distorting innovation in the market towards parties who can best capture this large payment.

As noted above, suppliers' payments to EG in relation to TNUoS demand residual charges are forecast to continue to increase rapidly. Therefore, we think that these distortions will also continue and will likely increase. We think that this may be driving up, and will continue to drive up, overall costs to consumers. We are concerned with these costs increasing further before any change to the embedded benefits regime are implemented.

To put this into a market context, the size of the current TNUoS demand residual is £45/kW which is over double the 2015 CM clearing price[16]. This is forecast to increase in four years to £72/kW. This payment is for operating in three half hour (triad) settlement periods. Since triad is defined after the event, EG have to generate in around 20 periods with a current value of £2,267/MWh. For the three triad periods only, the value is £30,220/MWh, over ten times the value that electricity users attribute to security of electricity supply (Value of Lost Load).

We note that the TNUoS demand residual charging arrangements are the focus of the CUSC modifications being raised by industry.

Any change to how the TNUoS demand residual charges are allocated will affect those generators that benefit from the current charging arrangements and the TNUoS demand residual payments. These are mainly controllable, non-intermittent EG, which can be more certain to generate during the triad periods - such as gas, diesel reciprocating engines, CHP, power from waste, anaerobic digestion and some storage. Solar EG does not receive these payments as it is usually unable to generate at times of peak net demand since between November and February these triad periods fall outside daylight hours. Wind, to the extent that it generates in the triad, may receive some TNUoS demand residual payments from suppliers.

We note that any changes to TNUoS demand residual charging arrangements may not affect EG that is behind the meter and that any change may further incentivise certain generators to locate behind the meter or via private wires. We discuss this further in section 7 below. We also note that it is important that all technologies, including CHP, are able to realise the value of the benefits they provide to the system. We encourage stakeholders to continue to progress work in related areas.

3.2 The TNUoS demand and generation locational signals

As we have stated in our previous work including Project TransmiT, we support the current

[14] In addition the €2.5/MWh restriction on generation charges means that any increase in TNUoS falls on demand charges

[15] When it would not be incrementally profitable to generate without the embedded benefit. The result of this being that more efficient plant are pushed out of merit, and less efficient, more expensive plant runs instead.

[16] The CM's aim is to ensure adequate capacity within an electricity system. Incentivising triad generation at double this price does not seem appropriate

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

approach of forward looking locational signals being provided to network users. These are designed to promote efficient use of the network by, for example, providing a signal to generators of the impact that their location decision has on transmission network investment. We think that this should continue to apply to EG in relation to its impact on the transmission system.

We note that currently the fact that EG is charged the negative of the demand locational charge, does provide such a signal to EG that generate at triad periods. However, as noted above, this signal is not the same as the signal received by TG and over-100MW EG who pay TNUoS and hence is a distortion.

The size of the differences in locational signal is much more modest than that of the TNUoS demand residual payments and can advantage EG or TG, depending on the location. Our initial thinking is that this may remain appropriate at least in the near term, but we note that locational signals for EG could be considered further as part of the related work set out in section 7 below. This could also be considered alongside thinking on local balancing under our Flexibility workstream looking at the roles of different parties in system and network operation.

3.3 The TNUoS generation residual

Avoidance of the TNUoS generation residual charges by smaller EG is one part of the embedded benefit. It currently accounts for a much smaller proportion of the total embedded benefit than the TNUoS demand residual payments and it is not forecast to escalate significantly. We therefore consider that avoidance of TNUoS generation residual charges is unlikely to be causing the sizeable distortions of a similar magnitude to those caused by the TNUoS demand residual payments. We do note that in the future it is possible that the generation residual will go negative – resulting in payments to generators[17]. Our initial thoughts are that adjustment to this element of the embedded benefit is less of a priority than adjustment to the allocation of TNUoS demand residual charges - given the relative size of the two associated embedded benefits. We propose to consider this issue further as part of the related work discussed below in section 7.

3.4 The BSUoS demand and generation charges

We have concerns that the BSUoS embedded benefit is likely to distort operational decisions (ie dispatch), by bringing some generators into merit at times when they should be out of merit (ie rendering it profitable for them to generate at times when otherwise it would not be profitable for them to generate).

However whilst we think there is a rationale for changing these charging arrangements, we do not currently think the BSUoS embedded benefit is a matter of similar priority to the TNUoS demand residual element of embedded benefit for the following reasons:

- the BSUoS embedded benefit is smaller and hence causes less distortion to dispatch;
- it likely has a lower overall cost to consumers; and
- there are significant interactions with possible future development of local balancing which Ofgem is considering through our work on issues relating to Flexibility. We consider that these need to be thought through carefully and future work in this area scoped alongside other changes.

3.5 Does EG provide any other benefit?

The locational element of the demand TNUoS charging arrangements should broadly reflect the costs and benefits that EG brings to the wider transmission system, in a similar way to wider generation transmission locational charges. However, we think that in addition to the benefits captured by the demand locational signal, EG (independent of their location) will also benefit the transmission system by avoiding investment at the importing GSPs (or increase costs if it drives investment at exporting GSPs). We note that National Grid over

[17] We note that there are several modifications on the €2.5/MWh cap. The €2.5/MWh cap on average generation charges is forecast to result in negative generation residual charges in future years. A negative residual charge prevents generators facing the full costs they impose on the transmission system, effectively subsidising all generators that pay TNUoS charges. We do not consider that this is consistent with the aim of a well-functioning wholesale market

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

the years have estimated the likely size of this benefit to be between £1/kW[18] and £6/kW[19]. We have seen other attempts to estimate the additional benefit that EG provide to the transmission system beyond that captured in the locational element of TNUoS charges but are currently not convinced by the rationale presented thus far and propose that industry considers how to calculate such a number and the justification for the approach taken.

3.6 Initial thoughts on our approach

We recognise that one option open to Ofgem is to undertake a Significant Code Review (SCR) and to consider any changes required to all elements of embedded benefits together with other relevant matters. We have considered this option but we consider that earlier action on this aspect of embedded benefits is clearly preferable given:

- the likely time involved;
- the scale of the potential distortion caused by TNUoS demand residual payments;
- the fact that these payments are increasing rapidly; and
- the significant impact that those payments may be having on the CM auctions.

We expect that the modifications being developed will enable this and will do so more quickly than is likely to be possible in the context of an SCR. We recognise the wider impacts of potential changes in this area and hence consider it is important that the benefits and costs are properly assessed. We expect these to be considered during the modification process and will also consider whether it is appropriate for us to also carry out an Impact Assessment before reaching a decision on any change. As discussed, there are some other elements of embedded benefits and related topics that we think may be suitable for a subsequent targeted review – see "related work" in section 7 below.

4. Transitional arrangements

We recognise that in considering modifications one issue we will need to consider is timing of any changes and whether there is a need for transitional arrangements. We note that in general terms there are several different approaches that can be taken when implementing change. These fit roughly into four categories:

- **Immediate change**: change is made as quickly as possible within the constraints of for example central systems;
- **Delayed change**: change is made after a longer period or where change is brought in slowly or phased;
- **Split implementation**: change is made for different users sooner than others. Often this would mean change is brought in sooner for new users than existing users; and
- **Grandfathering**: change is not made for a subset of users or a subset of investments made by specific users.

The matters we would take into account when considering any set of transitional arrangements between the current embedded benefits regime and any new regime would include:

- whether any delay to implementation is needed to give parties time to adjust to the new arrangements;
- whether transitional arrangements introduce discrimination into the charging arrangements (eg between those users for whom change is implemented earlier than other users);
- whether transitional arrangements introduce additional complexity into the charging arrangements;
- whether the potential future savings to consumers are negatively affected and to what extent (eg this could include whether transitional arrangements prevent further escalation of distortions);

[18] Informal Review Paper: Review of the Embedded (Distributed) Generation Benefit arising from transmission charges
[19] GB ECM-23 Pre-Consultation

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

- whether distortion in further long term arrangements can be avoided (ie the 2016 CM auction for delivery year 2020/21 and onwards);
- the extent of any impact on security of supply and whether transitional arrangements could mitigate these; and
- the extent to which investor confidence is affected.

Our initial thinking is that, if we are presented with a modification proposal that otherwise suitably addresses the TNUoS demand residual aspect of embedded benefits, it may be challenging to demonstrate that consumers would benefit from any delay in its implementation beyond 2019/20. We also think that it may be difficult to demonstrate that the costs and/or fairness of grandfathering the current arrangements for the TNUoS demand residual for existing EG could be justified given the significant costs and distortions that this would likely cause. However, we expect these matters to be considered, assessed and evidenced further as part of the ongoing modification process. We welcome input on transitional arrangements.

We are aware that any delay in implementation is likely to mean reduced consumer benefit. Therefore, we think there are likely to be benefits for consumers to prevent further escalation of the TNUoS demand residual payments above their current levels prior to implementation of any changes.

We note that the two modifications already put forward propose different approaches to transition. We think these will be important matters to consider as part of the modification process.

5. Potential distortions from other charging arrangements

The advantage to EG in terms of transmission charging arrangements could be offset to some extent if EG is disadvantaged in respect of connection charges and/or Distribution Use of System (DUoS) charges.

However, our initial thinking is that the different treatment of TG and EG in respect of connection charges and DUoS charges does not significantly disadvantage EG. In particular, we note that DUoS charges give EG a credit for offsetting investment between them and the GSP. This should reflect the different costs that they and TG impose on the distribution system.

Whilst there is significant ongoing work to improve connections and the connection process, for example through the Quicker and More Efficient Connection (QMEC) work that Ofgem is overseeing, we ask respondents to indicate whether they consider that there are any immediate issues in relation to distortions between transmission and distribution connection regimes and/or in respect of DUoS charges. If such issues are identified we would then consider how these would best be taken forward.

We welcome any evidence to help us to consider further whether other elements of the network connections and charging regimes are having a significant impact on the level playing field between different types of generation and demand including storage and other forms of flexibility.

6. Ongoing code modifications related to embedded benefits

We note that there seems to be a widespread view in the industry that the current level of the TNUoS demand residual payments, as one element of embedded benefit, is currently higher than is justified, although there is a range of views as to the extent of the distortion and how to progress its resolution.

Two proposed modifications to the CUSC have already been raised by industry members that are concerned about the distortions embedded benefit is causing, particularly to the CM. These are currently being progressed by the CUSC Modification Panel according to an accelerated timetable, led by National Grid.

Scottish Power has raised a modification (CMP264[20]) to stop any new EG, connecting after June 2017, from getting embedded TNUoS benefit. EDF has raised a modification

[20] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

(CMP265[21]) to remove the ability to get TNUoS demand residual payments from all EG with CM contracts, to be implemented in 2020. We have also seen that several alternatives to each modification have already been proposed by the modification group with the potential for additional alternatives to be raised during the working group consultation.

We encourage industry to get involved in the modification group process by either attending the meetings or responding to the consultations. This should include providing any data or analysis that would help progress the issues being raised as part of the process and would ultimately be taken into account when these proposals come to us for decision.

All modifications will be considered on the merits, and in accordance with relevant code objectives and our statutory duties.

7. Related work

In setting out the issues in this letter we focussed on TNUoS demand residual payments and EG, but we are conscious that there are a range of other matters which may require further work and modification in future.

As discussed above we have concerns about some other areas that affect the level playing field:

- other elements of embedded benefits, including some aspects of BSUoS; and
- allocation of sunk/fixed costs, including for storage and 'behind the meter' generation.

We are concerned that the BSUoS embedded benefit is likely to cause distortions mainly in relation to dispatch. Our initial thoughts are that this creates less significant distortions than TNUoS demand residual payments and hence imposes lower costs on consumers than the TNUoS demand residual element of embedded benefit. Accordingly, we see less urgency to address the BSUoS embedded benefits now. We also note that there is a drive now towards active management of EG (and distribution networks more generally) to support system and network operation. This will involve a greater role for DNOs (as they transition to be Distribution System Operators), the System Operator (SO) and/or could involve different market arrangements in the future. Some of these issues are covered in our forthcoming joint call for evidence with BEIS on a Routemap to a Smart, Flexible Energy System. We consider there is the potential for some future models to interact with BSUoS (and/or other elements of charging) more widely, for example, considering the value of some form of BSUoS charging for EG.

We have considered that changes to embedded benefit arrangements could lead to unintended consequences since it may push more connection of generation behind the meter or connection via private wires, which is likely to lead to inefficient outcomes. This is an important issue that will aim to take into account in future related network charging work.

We are aware of the importance of ensuring charging for storage ensures both transmission and distribution connected storage can compete on a level playing field with other forms of flexibility. We will be seeking evidence on how the current charging regime may affect that in our forthcoming call for evidence with BEIS. Views we receive will help inform our future work and priorities.

There are significant issues to consider and hence we think that it would be appropriate to take them forward through further work. We plan to set out further thinking on the other elements of the embedded benefit and the allocation of sunk and fixed costs including for storage and 'behind the meter' issues in the autumn.

We are aware that industry is progressing other work on charging at distribution level with the CDCM and EDCM reviews; at transmission level with the National Grid review and at a cross transmission and distribution level with the ENA overseeing several working groups. Others, such as Energy UK, have considered network charging arrangements. We believe good progress can be made through industry effort and are aware of the need for co-

[21] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

ordination. We will be engaging with the industry on how best to take forward these wider issues.

Request for stakeholder views

As mentioned above, we would encourage interested stakeholders to provide views and evidence around any of the issues raised as a response to this letter. Stakeholders are also encouraged to feed relevant views into the modification group process including the consultations.

Any responses to this letter are requested by **Friday *23 September 2016***. Unless clearly marked confidential, all responses will be published on our website. If you would like to get in touch to discuss these issues please contact Dena Barasi (dena.barasi@ofgem.gov.uk) or Andrew Self (andrew.self@ofgem.gov.uk).

Yours faithfully,

Frances Warburton
Partner
Energy Systems

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**