nationalgrid

Informal Review Paper

Review of the Embedded (Distributed) Generation Benefit arising from transmission charges

This paper forms part of National Grid's informal review of the 'embedded benefits' arising from transmission charges and, in particular, Transmission Use of System (TNUoS) charges. We are interested in stakeholder views and evidence in relation to these benefits, and welcome responses by 14th February 2014.

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Contents

1	Executive summary	1
2	Background	4
3	Relevant Ongoing Industry Developments	13
4	Analysis	16
5	Focus group discussions	26
6	National Grid views and potential options and next steps	39
7	How to Respond	45

1 Executive summary

1.1 Background

This review paper considers the embedded generation benefit arising from transmission charges, and primarily the benefit arising from Transmission Use of System (TNUoS) charges. TNUoS charges are levied on all transmission connected generators, licensable embedded generators, and suppliers of both half-hourly (HH) and non-half hourly (NHH) demand, and are set to recover the allowed revenues of Transmission Owners (TOs) who own assets that comprise the GB transmission system. Other transmission charges are Balancing Services Use of System (BSUoS) charges which recover the costs of operating the transmission system, and connection charges which recover the costs of connection assets.

Embedded generators are those generators which are connected to, and therefore export their power onto, distribution networks. In most cases this nets with demand also connected to the distribution network. However increasingly this can exceed the local demand from time to time resulting in distribution systems exporting power onto the transmission system.

Suppliers are charged demand TNUoS on the basis of their net demand, i.e. gross demand minus the export for embedded generation. Therefore embedded generation has a value to suppliers equal to the saving they create in TNUoS charges. This value forms the first part of the embedded benefit arising from transmission charges.

With the exception of licensable embedded generators with a capacity of greater than 100MW, embedded generators do not pay TNUoS charges. The avoidance of this charge could result in a competitive advantage for the embedded generator, and therefore this could be considered to form the second part of the embedded benefit arising from transmission charges.

The wider TNUoS charge can be considered as being made up of two elements;

- A locational element reflecting the unit cost of transmission investment at a point on the GB system. At a high level the locational elements for generation and demand users can be considered equal and opposite. Through its netting, an embedded generator can be considered to have an implicit value equal but opposite to the demand signal, and therefore equivalent to the signal received by a transmission connected generator.
- A residual element added on a capacity basis to ensure TNUoS charges recover the correct revenue. Residual elements differ for generation and demand customers.

As both embedded and transmission connected generation receive equivalent locational signals, the embedded benefit arising from TNUoS charges can be estimated to be the summation of both demand and generation residual elements. In 2013/14 this is valued up to £30.32/kW. To capture the full benefit an embedded generator would need to run at full output during appropriate peak demand periods (e.g. the Triad). As certain generation technologies cannot control their output, they cannot necessarily be in receipt of the full benefit.

1.2 The need for the review of embedded benefits arising from TNUoS charges

In 2005, the Scottish systems were incorporated into the GB electricity market arrangements. In Scotland the 132kV networks, due to the extent of parallel, active circuits, were designated as transmission. In England and Wales such systems, which tended to be more radial remained designated as distribution. Generators connected to 132kV networks in Scotland therefore started paying TNUoS charges; even those with a capacity of less than 100MW, and were therefore not in receipt of the embedded benefit arising from TNUoS charges.

At the time it was decided that interim arrangements should be put in place. This would address concerns from users in Scotland that there was not a level playing field between these two classes of generator in advance of a broader review. These arrangements took the form of a discount to TNUoS charges for eligible generators equivalent to 25% of the total residual proportion of the annual TNUoS tariff. This discount was implemented in a time limited manner through Standard Licence Condition C13 (SLC C13) of National Grid's transmission licence. The current expiry of this condition is 1st April 2016 This assumes that any changes to the enduring arrangements identified through this review will be sufficiently developed by this time.

In 2007 Ofgem took forward industry debate on the subject through a discussion document and the Transmission Arrangements for Distributed Generation (TADG) working group[1]. The TADG process explored a number of issues with distributed (embedded) access and charging arrangements with a view to developing high level options for an enduring solution. A number of models were developed, but there was no industry consensus as to which model was the most appropriate to take forward and, in conclusion, Ofgem noted that it was now the responsibility of the industry to take forward proposals by submitting change modifications to the industry codes or other documents. Ofgem also considered that National Grid should undertake a broader review of the embedded generation charging arrangements; '*We consider that NGET should undertake a review of the drivers of the costs associated with the residual TNUoS charge, taking into account the impact of distributed generation on such costs. It seems logical that distributed generation should pay less than transmission connected generation because it avoids the need for some network costs (such as costs of increasing transformation capacity at the local distribution and transmission interface), but we believe that the value of these embedded benefits does require further review.*'

Noting the need for enduring arrangements to be in place for April 2016, we are therefore taking forward this broader review of distributed (embedded) generation charging arrangements. The intent of this review is to inform any formal modification proposal to the Connection and Use of System Code (CUSC) which contains the TNUoS charging methodology. Any such proposal will be taken through the normal CUSC open governance process.

1.3 The review thus far

We commenced our broader informal review of embedded benefits arising from TNUoS charges earlier in 2013 with the establishment of an informal industry focus group. We had significant interest from stakeholders regarding the group, and were over-subscribed for membership. We therefore had to limit membership to ensure a representative cross-section of stakeholder views. Section 5 of this report contains details of the Focus Group discussions and the membership of the group. Whilst this is a National Grid report, section 5 has been developed with the Focus Group to

[1] All documentation from the TADG working group can be found at: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TADG/Pages/TADG.aspx

provide a good overview of the areas of discussion. We thank the Focus Group for their help in this area which has helped shape the rest of the report and our thinking.

We have also discussed our review on a bilateral basis with many of the stakeholders not directly involved with the Focus Group. This has equally provided us with helpful information for our review, as has our engagement through industry meetings, and we would like to thank all those involved so far.

We are conscious that, whilst a significant number of stakeholders have had the opportunity to discuss this review with us, others may not, and may have further questions or concerns in regards to the work we have carried out to date. We have therefore put together this report to inform stakeholders and also allow for further opportunity for all stakeholders to feed evidence and views into this process. To that end we present in section 6 of this report a spectrum of potential options for consideration, and pose a number of questions for industry response. We are particularly interested in any further evidence that stakeholders may wish to present. These potential options can be considered broadly in four areas;

- Treatment of the C13 licence issue alone. This would consider treatment of the 'small generators' discount' alone through options such as establishment in the CUSC or simply removal.
- Better reflecting the impact of exporting GSPs on transmission investment. The Focus Group suggested that the increasing frequency of exporting GSPs on the GB system was a potential area of improvement in the TNUoS charging methodology and should be considered.
- Charging the demand HH residual on a gross basis, i.e. prevent netting of the demand HH residual only. Options in this area would focus on demand charging arrangements only.
- Charging the demand HH residual on a gross basis and explicitly charging embedded generation. Options in this area would review the charging arrangements for both the demand and generation residual elements of the TNUoS charge.

1.4 Next Steps

This report is published as part of an informal consultation seeking stakeholder views and, in particular, evidence on the embedded generation benefit arising from TNUoS charges. Following industry discussion at the Transmission Charging Methodologies Forum (TCMF) in November 2013, and to allow for the holiday period, this consultation will remain open until 14th February 2014.

We will then carefully review the responses received to this consultation before, if necessary, submitting a CUSC modification proposal(s) in Spring 2014.

2 Background

2.1 System Operator licence obligations

As the transmission licensee, authorised to co-ordinate and direct the flow of electricity onto and across the transmission system within Great Britain, National Grid has duties under the Electricity Act to develop and maintain an efficient, co-ordinated and economical transmission system and to facilitate competition in generation and supply.

Along with these high level duties, we are obliged under our transmission licence:

(i) to keep the Use of System Charging and Connection Charging Methodologies at all times under review

(ii) to make such modifications of the Use of System Charging Methodology and Connection Charging Methodology as may be requisite for the purpose of better achieving the relevant objectives, which are:

(a) to facilitate effective competition in generation and supply;

(b) to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses;

(c) in so far as is consistent with a) and b) above, as far as reasonably practicable, they properly take account of the developments in transmission licensees' transmission businesses.

(d) for connection charging, in so far as is consistent with a), b) and c) above, of facilitating competition in the carrying out of works for connection to the GB transmission system

In addition to the relevant charging objectives above, the transmission licence (standard condition C7) also prohibits National Grid from discriminating against any User or class of Users unless such different treatment reasonably reflects differences in the costs of providing a service.

The Use of System Charging and Connection Charging Methodologies now form section 14 of the Connection and Use of System Code (the CUSC), and therefore are subject to open governance arrangements, i.e. any CUSC Party[2] can propose changes to the Charging Methodologies. Hence, in order to discharge our transmission licence obligations in this area, we are required to raise a CUSC modification proposal where we believe an improvement could be made to the Charging Methodologies which better meets the relevant objectives. Such proposals are then subject to a formal governance process involving industry stakeholders, prior to an Ofgem determination.

The purpose of this document is to inform interested parties of our review of Embedded (Distributed) Generation benefit and to invite comments. These will allow us to shape any formal CUSC modification proposal in 2014.

[2] Ofgem also have the powers to allow non CUSC parties to submit proposals

2.2 The Changing GB Energy Mix

Currently, the majority of electricity in Great Britain is supplied via the electricity transmission system. Large transmission connected generators have minimised costs through economies of scale and provided secure, cost-effective delivery of energy by pooling back-up capacity.

Distributed generation (DG), also referred to as embedded generation, is connected to distribution rather than transmission networks and generally produces energy on a smaller scale, often closer to where it is consumed. There are many distributed generation technologies such as hydro, wind power, solar panels, combined heat and power as well as other non-renewable generators.

The government's Energy White Paper 2007 outlined the challenges faced in tackling climate change and highlighted the contribution that distributed generation, ranging from household to community-scale, can make in this respect. It stated a desire to provide opportunities for growth in DG by removing barriers and putting the right incentives in place to promote DG where it proves to be cost-effective[3].

Through some initial modelling undertaken in support of the White Paper, the preliminary findings suggested that the costs to the UK of some DG technologies may be competitive with the costs of centralised technologies, but that the overall system costs are likely to be lower if we retain a framework where DG is a complement rather than an alternative to centralised generation.

Where a particular technology or class of technologies (i.e. renewables) require additional economic support, either due to the nature of the technology or for wider social and environmental reasons, this is generally best achieved through a 'keyhole economics' approach. This means a targeted and transparent subsidy mechanism for the specific technology type requiring support rather than through a blanket change to the arrangements for all parties, as the latter is far more likely to have unintended consequences and create market distortion.

For example, to support the development of small DG, the UK government introduced a banded Feed-in-Tariff (FiT) scheme as an incentive to renewable electricity installations up to a maximum capacity of 5MW in April 2010. This scheme complements the existing Renewables Obligation, which is generally available as an option to renewable generators above a 50kW threshold and the Renewable Heat Incentive being developed for heat from renewable sources at all scales. By aiming to deliver a rate of return of between 5% and 8%, the FiT scheme was expected to support over 750,000 small scale low carbon electricity installations[4] and supply approximately 2% of GB demand by 2020 from these installations.

2.3 Impact on the transmission system and charges

Historically, due to the largely unidirectional flow of power from the high voltage transmission network onto the lower voltage distribution networks, the technical as well as commercial treatment

[3] Page 84 - http://www.berr.gov.uk/files/file39387.pdf

[4] Government response to FiT consultation - http://www.decc.gov.uk/assets/decc/Consultations/Renewable%20Electricity%20Financial%20Incentives

of these networks within the industry framework was largely distinct and at times disparate. In future, as an increasing amount of energy is generated within distribution networks the overall nature and effect of electricity networks as a whole will need to be increasingly reflected within the wider framework. This is conceptually illustrated in Figure 1 below. The Focus Group have recognised these impacts, evident in their discussion on exporting GSPs (see page 35).

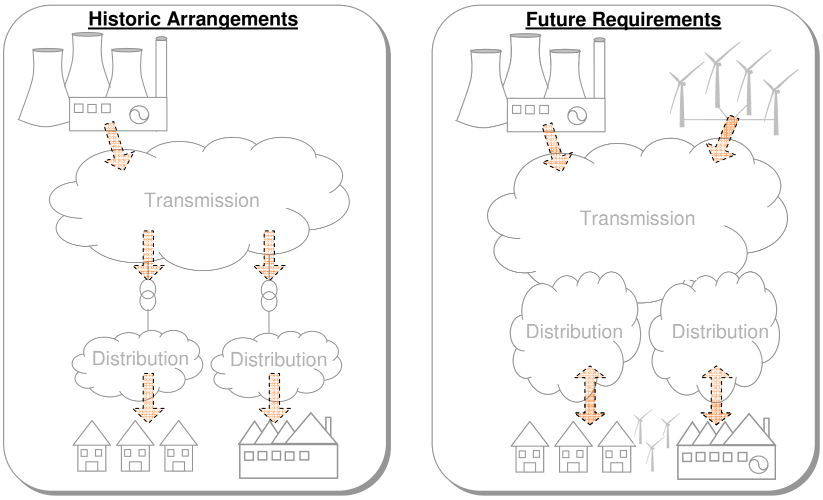

Figure 1

The methodologies for the calculation of transmission charges are required to reflect the costs of the relevant transmission activities. Historically embedded benefits arising from transmission charges have been considered to be representative of the savings in these costs due to embedded generation. However, as the level of DG increases it can be argued that these benefits are no longer appropriate. National Grid understands that embedded benefits may arise through three elements of transmission charges;

- Transmission Network Use of System (TNUoS) Charges – These charges recover the costs associated with Transmission Owner (TO) activities such as construction and maintenance;
- Balancing Services Use of System (BSUoS) Charges – These charges recover the costs associated with System Operator (SO) activities such as system balancing and constraint management;
- Transmission Losses – These are adjustments to settlement metering to account for losses on the transmission network.

In all three cases the benefit arises through the netting effect of embedded generation with demand. The Focus Group briefly discussed each of these benefits when setting out the scope of the review, and concluded that the primary focus should be on TNUoS charges. This discussion is set out in further detail in section 5.1. It should be noted that in all cases, the reduced liability on one party increases the charges to all other parties, as the overall costs recovered are unchanged. The value of the benefits arising from BSUoS and Losses are described in sections 2.5 and 2.6 of this report respectively, and we note that these are not covered by Licence Condition C13. The value of the benefits arising from TNUoS charges is discussed at further length on page 16.

2.4 Embedded Benefits relating to TNUoS charges

Transmission Network Use of System (TNUoS) charges are paid by generators and suppliers (including directly connected customers). For generators this is comprised of local and wider charges. Local charges reflect the infrastructure costs of the connecting substation and any spur required to connect the generator into the wider transmission system. Wider TNUoS tariffs consist of two elements;

- A locational element reflecting the cost of the wider transmission system; and
- A residual element added to the tariff to ensure correct revenue recovery from generation and demand users.

Locational elements are derived from a peak demand DC load flow algorithm on an incremental forward looking basis. This is carried out for each node on the network. At that level, locational signals for generation users are equal and opposite to demand signals. These nodal signals are grouped together into zonal signals which form the basis of the locational element of the wider TNUoS tariff. This is shown stylistically in
Figure 2 although in reality, due to differences in zoning criteria between generation and demand zoning, there are limitations to the accuracy of these signals. However it is a reasonable approximation to say that embedded generation, as negative demand, receives the inverse of the demand signal and therefore an equivalent locational signal to transmission connected generation. If there was only the locational element to the wider charge then there would be no embedded benefit relating to TNUoS charges.

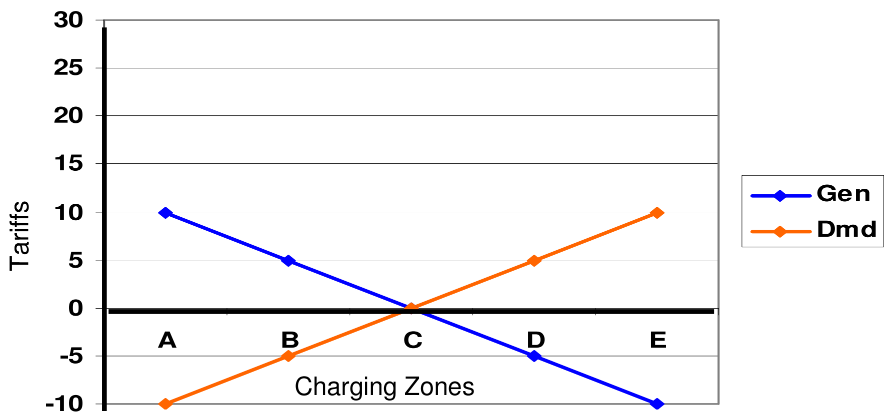

Figure 2

The residual element is required to ensure TNUoS charges are set to recover the correct overall revenue. National Grid collects revenues for all onshore and offshore Transmission Owners (TOs) based on the amount agreed with Ofgem as part of each TO's price control settlement. In addition, the TNUoS methodology requires that 27% of total revenue is collected from generation users and 73% from demand users. The residual elements are applied on a flat £/kW basis for generation and HH metered demand and a flat £/kWh basis for NHH demand. As demand is charged on a net basis, chargeable demand can be reduced through netting with embedded generation, and this can create a saving equal to the demand residual element. This forms part of the embedded benefit arising from TNUoS charges. The netting effect that embedded generation provides is illustrated in Figure 3 below.

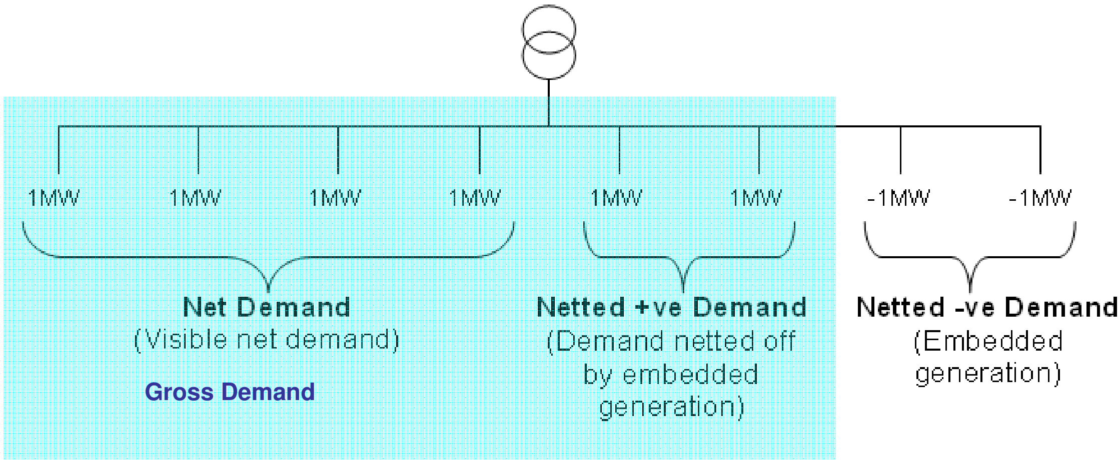

Figure 3

In the figure above, a GSP has 6MW of gross demand, 2MW of which is netted off by embedded generation (negative demand), leaving suppliers charged TNUoS on 4MW of net demand.

This netting occurs at the demand charging level which is currently at a GSP group level of which there are 14 across GB. This is due to supplier metering arrangements. This means that, from a TNUoS charging perspective, demand can net with embedded generation even though they are in separate GSPs and therefore require the transmission network. For instance, within the south Wales a supplier could have demand contracted in Cardiff and separately have a contract with an embedded generator in Pembrokeshire. Despite there not necessarily being a distribution network connecting these areas the supplier and generator would net to avoid TNUoS.

The second part of the embedded benefit arising from TNUoS charges relates to the avoidance of generation TNUoS charges by embedded generation. If a supplier is looking to contract with generation, then this avoided charge could give an embedded generator a commercial advantage over a transmission connected generator. This may lead to inefficient behaviour such as the dispatch of relatively uneconomic or more polluting generators, as well as inefficient generator connection and/or network investment decisions. As both sets of generators receive equivalent locational signals within their TNUoS charges (the transmission connected generator explicitly through their generation charge, and the embedded generator implicitly through their embedded benefit) then this avoidance of the generation TNUoS charge relates to the residual element only. We recognise that the embedded generator may pay its own network charges relating to its distribution connection, and hence we feel that a review of this element of the embedded benefit needs to consider the overall network costs paid by both transmission and distribution connected generation. In section 4.5 we present a comparison of such charges for 132kV connected generation with capacity of less than 100MW.

In summary, the TNUoS benefits available to embedded generation arise due to;

- the ability of a supplier to net off the negative demand (embedded generation) against its actual demand for the purposes of TNUoS charges. This can be considered to be equal to the demand residual of TNUoS.
- the avoidance of the generation residual element of TNUoS charges by the embedded generator. This can be considered to be equal to the generation residual element of TNUoS.

How this benefit is captured depends on the embedded generator's setup under the Balancing and Settlement Code (BSC) and their contractual relationship with National Grid and / or supplier. The embedded generator can negotiate with the supplier to receive a proportion of this saving; the proportion of benefit shared is commercially confidential and varies contract to contract. Embedded generators who contract directly with National Grid and set themselves up in the BSC as lead party for their output will receive the benefit directly.

Some embedded generators do pay transmission charges. These are licensable generators (those generators who do not need a licence are referred to as 'exemptible') of over 100MW capacity connected to the 132kV system in England and Wales. These generators may also pay distribution charges.

2.5 Embedded Benefits relating to Balancing Services Use of System (BSUoS) Services

Through the current Balancing and Settlement Code (BSC) arrangements, embedded generation can sell their energy into a national energy account and have access to the GB-wide market. As both the embedded generator and the associated supplier avoid BSUoS charges, the embedded BSUoS benefit is twice the BSUoS charge. As well as avoiding paying BSUoS, embedded generation are able to receive it either directly or through a supplier like the TNUoS benefit.

BSUoS charges are charged on a £/MWh basis for each settlement period and apply to both generation and demand users. In 2012/13 the average settlement period charge was £1.47/MWh. The benefit amounts to the total of both the saving of the embedded generator and that of the netted demand, i.e. £2.93/MWh.

2.6 Embedded Benefits relating to Transmission Network Losses

Arguably embedded generators, by virtue of being notionally located closer to where electricity is consumed, reduce the losses inherent in transmitting electricity across the transmission network. However, this needs to be considered in the context of all other generation within GB. Additional generation, unless precisely and continuously matched with a local demand, will impact on the wider transmission network and other generation. In locations with an excess of overall generation at any voltage level, it will contribute to an overall increase in transmission losses.

The cost of losses is recovered through adjustments to the energy that users deliver or take from the market. As the BSC party responsible for a supplier's energy account can net embedded generation off their demand requirement, embedded generation essentially reduces a supplier's liability to pay for transmission losses. Again with the other benefits the total benefit is twice the absolute charge. This is estimated to be around 2% of the wholesale cost of energy, and therefore the value of the benefit is estimated at approximately £2/MWh when accounting for both generator and suppler effects.

2.7 Recent Industry History

During the development of the British Electricity Trading and Transmission Arrangements (BETTA), industry parties raised a number of issues with regard to the treatment of distributed generation within the transmission charging and access arrangements and how these would be extended across Great Britain.

Under BETTA, 132kV networks in Scotland were categorised as transmission and therefore generators connected to them would pay transmission charges. 132kV onshore networks in England and Wales had been categorised as distribution and hence generators connected to them pay distribution charges and would receive the embedded benefit (other than those with a capacity greater than 100MW who also paid transmission charges). Subsequently offshore 132kV networks were similarly categorised as transmission and therefore generators connected to them also pay transmission charges and qualify for similar considerations.

In a consultation document published in November 2003[5] Ofgem and the DTI were of the view that, "*the operation of the TNUoS embedded benefit confers a benefit to small distribution-connected generation relative to small transmission-connected generation, and that this difference in treatment is not proportionate. Its continuation within a common set of GB arrangements does not therefore appear consistent with the objectives of BETTA*."

In addition, due to the different definitions of transmission between Scotland and the remainder of Great Britain, 132kV exemptible generators who were transmission connected in Scotland would not receive these benefits under the prevailing arrangements whereas 132kV exemptible generators who were distribution connected in England and Wales would.

At the time it was decided that interim arrangements. These arrangements took the form of a discount to TNUoS charges for eligible generators equivalent to 25% of the total residual proportion of the annual TNUoS tariff. At this time around 660MW of generation qualified for this benefit which was forecast in 2003/4 prices at approximately £2.39. 2013/14 figures are provided in section 4.4 of this report.

This discount was implemented in a time limited manner through Standard Licence Condition C13 (SLC C13) of National Grid's transmission licence. The initial expiry of the discount was due for 1st April 2008 (which has since been extended until March 2016) on the basis that enduring arrangements would be sufficiently developed by this time.

Following BETTA go-live Ofgem took forward industry debate through a discussion document and the Transmission Arrangements for Distributed Generation (TADG) working group[6]. The TADG process explored a number of issues with DG access and charging arrangements with a view to developing high level options for an enduring solution. Industry parties brought forward a number of potential models, focused on agency arrangements, which were reviewed against Ofgem's principles for change:

i) Cost-reflectivity,
ii) Efficiency in allocation of transmission access, and
iii) Proportionality.

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[5] Paragraph 8.25 - http://www.ofgem.gov.uk/Networks/Trans/Betta/Publications/Documents1/5168-Small_Generators_issues_20nov03.pdf

[6] All documentation from the TADG working group can be found at: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TADG/Pages/TADG.aspx

There was no industry consensus as to which model was the most appropriate to take forward and, in the Working Group Report published in July 2007[7], Ofgem noted that it was now the responsibility of the industry to take forward proposals by submitting change modifications to the industry codes or other documents.

In an accompanying letter published alongside the report[8], Ofgem set out their provisional thinking in light of the work of the Group with the intention of providing further context to inform any potential change proposals being considered by industry parties. Specifically, Ofgem noted the importance that transmission charging arrangements reflect the costs imposed on the transmission network and give appropriate credit for the benefits provided. This was on the grounds that this promotes the economic development of the transmission network and helps to ensure that competition in generation and supply takes place on a level playing field. Additionally, Ofgem noted the importance that transmission access is allocated in an efficient and coordinated manner, and that the administrative and regulatory burden for smaller participants in the market is proportionate.

Ofgem also considered that National Grid should undertake a broader review of the DG arrangements; '*We consider that NGET should undertake a review of the drivers of the costs associated with the residual TNUoS charge, taking into account the impact of DG on such costs. It seems logical that DG should pay less than transmission connected generation because it avoids the need for some network costs (such as costs of increasing transformation capacity at the local distribution and transmission interface), but we believe that the value of these embedded benefits does require further review.*'

2.8 Models discussed

Previous industry discussions have noted that an agency model would be an appropriate means for a smaller DG to deal with transmission issues, as this could help reduce the burden on the DG and take account of the diversity of generation. Two potential agencies, a Supplier and a DNO, have been put forward which both avoid the need for distributed generators to contract directly with National Grid. These agency models remain of relevance today.

Both of these agencies have also been considered on the basis of gross and net demand. Net demand is the current methodology where demand is charged net of embedded generation output. An alternative methodology is to charge both gross demand and potentially embedded generation. The subject of gross and net demand has been reviewed by the Focus Group and is detailed on page 32. Figure 4 outlines the four possible agency models described in brief below.

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[7] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TADG/Documents1/070723_Final_TADG_Working_Group_Report.pdf

[8] http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TADG/Documents1/070730_TADG_Covering_Letter_final.pdf

Possible Options for Agency Models

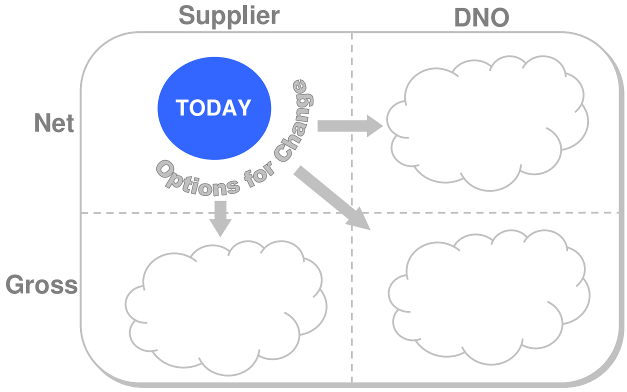

Figure 4

Net Supplier

Current arrangements, where suppliers contract with distributed generators and pay use of system charges on the basis of their total demand net of distributed generation is akin to a Net Supplier Agency Model.

Gross Supplier

A gross supplier model would maintain the existing contractual relationship between distributed generators and suppliers. However, suppliers would need to take account of changes within the individual contracts in place with their customers. By charging suppliers on the basis of gross demand (and possibly gross generation depending on the sub-option chosen) the TNUoS embedded benefit can be treated explicitly, i.e. the avoided transmission investment associated with connecting generation to the distribution network would be discounted from the gross tariff. In addition, a de-minimis threshold below which charges would continue on a net basis would be required.

Gross DNO

A gross DNO model would provide the same incremental improvement in cost-reflectivity as a Gross Supplier model, but would additionally require a change in contractual relationships for DG from supplier to DNO.

Net DNO

A net DNO model would retain the TNUoS embedded benefit and, as such, not directly improve the cost-reflectivity against the current baseline. Nevertheless, if implemented in conjunction with nodal, explicit access rights (as opposed to the existing zonal, implicit rights held by suppliers) this model could indirectly address the issue of cost-reflectivity and the facilitation of effective competition. Through full exit reform, DG would no longer be able to sell output into the wider market and implicitly utilise the transmission network. Instead, DG would operate in a local, nodal market facilitated by the DNO who would purchase explicit entry and/or exit rights from the transmission system operator.

3 Relevant Ongoing Industry Developments

The change in the GB energy landscape has far reaching consequences and, as a result, there are a number of other ongoing initiatives which should be considered alongside any review of embedded generation charging arrangements.

3.1 Electricity Market Reform

The Government set out its intention to reform the electricity market in the EMR (Electricity Market Reform) White Paper[9] and the EMR Technical Update[10] in 2011. The purpose of EMR is to deliver the UK Government's objectives of providing security of supply at a cost that is affordable to the consumer, whilst at the same time meeting our climate change responsibilities by providing incentives to generators through a dedicated support mechanism.

The key elements of EMR include:

- A mechanism to support investment in low-carbon generation in the form of Feed-in Tariffs with Contracts for Difference (CfD);
- A mechanism to support security of supply, if needed, in the form of a Capacity Mechanism; and
- The institutional arrangements to support these reforms

Contracts for Difference (CfDs)
CfDs provide developers of low carbon generation projects with a guaranteed price for their energy, known as a 'Strike Price' for a period of 15 years. If the wholesale price is lower than this, they get a 'top up' payment to the Strike Price, but if it is higher, they pay back the difference. Strike prices will vary depending on technology and year of signing.

Embedded generation above 5MW will be eligible to sign up for a CfD although the metering arrangements for certain embedded generation is yet to be decided.

The Capacity Mechanism
The Capacity Mechanism is designed to ensure that there is enough capacity to meet the government's standard for security of supply. It will provide generators with a stable monthly payment to ensure they are available and can generate electricity when it is required. Embedded generation will be eligible to sign up to participate in the Capacity Mechanism.

DECC has recently published a public consultation on the Secondary Legislation which is expected to become law in July 2014. The first Capacity Mechanism auction will be held in November 2014 and the first CfD contracts could be signed by the end of 2014.

[9] https://www.gov.uk/government/publications/planning-our-electric-future-a-white-paper-for-secure-affordable-and-low-carbon-energy
[10] https://www.gov.uk/government/publications/planning-our-electric-future-technical-update

3.2 Project TransmiT (CMP213)

Project TransmiT is Ofgem's independent and open review of electricity charging and associated connection arrangements. The aim of Project TransmiT is to ensure that arrangements are in place to 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.

In June 2012, following an Ofgem led industry process, NGET raised a CUSC modification proposal, CMP213, seeking to make three incremental changes to the TNUoS charging methodology. The first of these was to better reflect the costs and benefits imposed by different types of generators on the electricity transmission network. The CUSC process has now concluded and proposals now rest with the Authority for a determination.[11]

Through August 2013, Ofgem issued a 'minded to' view within their impact assessment consultation. This view contained a proposal that they believe better reflected the costs and benefits imposed by different types of generators on the electricity transmission network and on which they sought industry feedback. This proposal recognised the impact of generation not just on system peak requirements for transmission investment, but also on the year round effect of that generation. There is no significant impact to demand TNUoS charges from this proposal.[12]

If implemented, this proposal will change the basis for generation TNUoS charges. The embedded benefit will still be constituted in part from the avoided generation residual element. Whilst CMP213 would not directly affect an embedded generator, there may be a case that embedded generation should similarly be exposed to the year round effect of its operation. In that event, such work could tie in with the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) review, GSR016, mentioned below.

3.3 Grid Code Review GC0042 – Information on Embedded Small Power Stations and its impact on Transmission System Demand Workgroup Report

This proposal seeks to modify the Grid Code to include Embedded Small Power Stations of registered capacity of 1MW or more in Network Operators' Week 24 submission[13] to facilitate National Grid's development and operation of the Transmission System.

This proposal states that, from a design perspective, embedded generation needs to be accounted for in order to determine the right level and timing of transmission network reinforcement. An example is given of the investment requirements for the transmission boundary between Scotland and England where the proposer estimates that embedded generation contributes almost 600MW to this requirement. This is shown in Figure 5 below;

[11] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

[12] https://www.ofgem.gov.uk/publications-and-updates/project-transmit-impact-assessment-cmp213-options

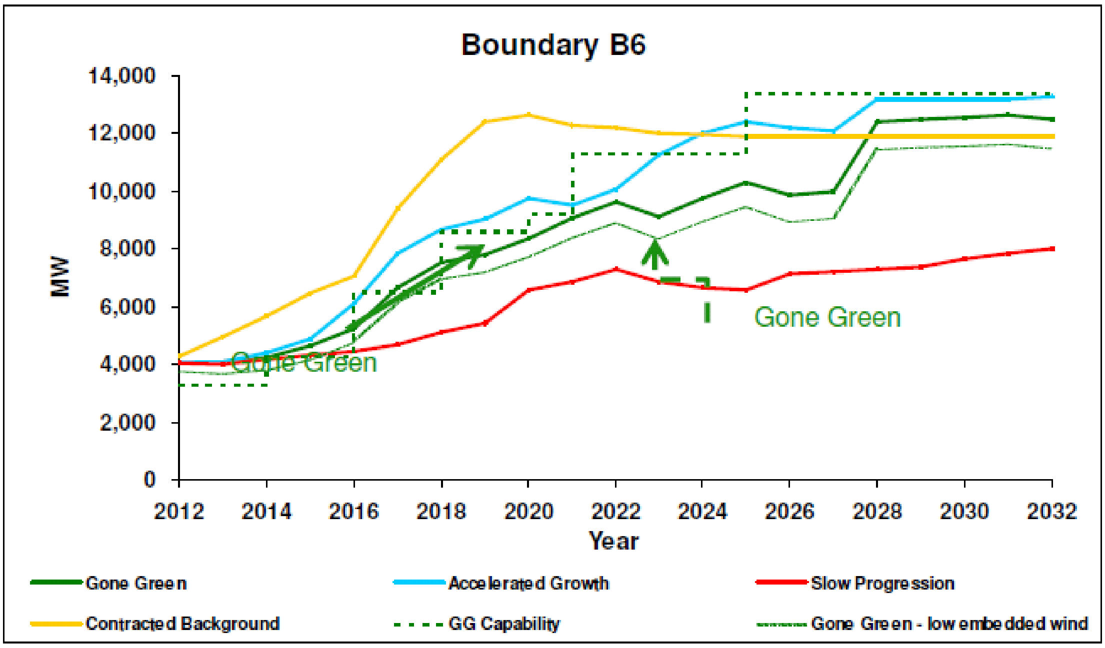

Figure 5

The GC0042 Workgroup has proposed that the following additional information would be requested from DNOs on an annual basis for all small embedded power stations with a registered capacity of 1MW or greater;

- Technology / fuel type
- MW capacity
- Electrical and geographical location

The GC0042 Workgroup has now finalised and a consequential Distribution Code modification proposal is shortly to be raised. Both proposals are expected to be finalised in 2014, with implementation in 2015.

3.4 NETS SQSS Industry Review Group GSR016 – Embedded Generation Assumptions and Application of Economy Criteria

The NETS SQSS Review Group notes that presently the effect of small and medium embedded generation is through netting off gross demand. The group, in their terms of reference, note that this approach may no longer be suitable as the penetration of embedded generation increases, potentially resulting in significant underestimation in the determination of required transmission capability. This Review seeks to determine a more realistic setting for such generation recognising their impact on transmission investment requirements. The group's terms of reference were agreed in November 2013 and they are expected to conclude in 2014.

4 Analysis

4.1 Introduction

In this section we present background analysis to help the reader understand the potential extent and impact of the embedded benefits arising from TNUoS charges, and also appreciate the potential level of embedded generation going forwards. We recognise that there are relevant areas where better data may be available to other industry parties, for example typical distribution use of system charges, and we would welcome any further analysis presented to us by stakeholders to shape any potential future CUSC modification proposal.

4.2 What is the value of the embedded benefit arising from TNUoS charges?

During focus group discussions it was questioned what the value of the embedded benefits was. National Grid conducted analysis to understand the current value of embedded benefits and presented their analysis back to the focus group.

Suppliers can realise benefits when their charges are reduced through netting off their gross (true) consumer demand with their embedded generation output, which is treated under the current arrangements as negative demand. This benefit, depending on their commercial arrangements, is shared between the Supplier and the embedded generation. How explicit this arrangement is, or the proportion each party receives, is commercially confidential and varies from contract to contract.

In section 2.4 the derivation of the TNUoS embedded benefit was discussed in detail. Broadly, due to the netting of embedded generation with demand, the embedded benefit arising from TNUoS charges can be considered to be the summation of the two residual elements. Embedded generation avoids the generation (G) residual element that transmission generation is liable to pay; they also net off a proportion of a supplier's true consumer demand, reducing the charges that the supplier would be liable to pay (the demand (D) residual element). In 2013/14 the G residual element is £4.81/kW and the D residual element is £25.41/W, giving a TNUoS embedded benefit of £30.22/kW. On this basis, Figure 6 shows the TNUoS embedded benefit in 2013/14 prices from period 2011/12 to 2014/15. The 2014/15 figures are based on the quarterly update forecast published in November 2013.

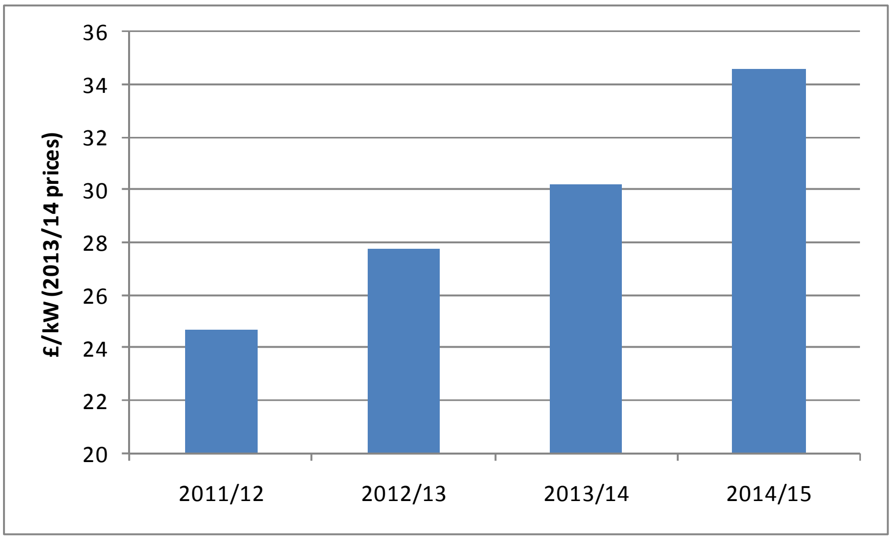

Figure 6 : Value of embedded benefit (£/kW, 2013/14 prices)

There are a number of caveats when considering data blanket value for the embedded benefit arising from TNUoS charges. Firstly, demand and generation zones cover different geographical parts of the country. So the 2013/14 TNUoS embedded benefit can range from £41.30/kW to £27.54 depending on the location of the generator. Also the benefit is based on the generator's ability to net with demand at the Triad. The Triad is the three settlement periods of highest transmission system demand within the November – February period of a Financial Year which are separated between each other by at least ten clear days. Certain technology types (intermittent generation) are unable to control their output and consequentially could receive a much lower benefit.

4.3 How much is the total TNUoS embedded benefit?

Based on the information published by National Grid in its 2013 Future Energy Scenarios (FES) document[14], the forecast level of embedded and micro-generation out to 2020 is given in Table 1 below. It should be noted that National Grid has no direct contractual link with embedded generation and therefore the quantities shown are our best view (Gone Green background) compiled from a number of sources such as the Governments DUKES report and DNO week 24 data submissions.

Embedded Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020
Biomass	2,520	2,542	2,565	2,588	2,610	2,633	2,655	2,678	2,701
Offshore Wind	678	678	752	752	803	803	803	803	803
Onshore Wind	2310	2455	2742	3046	3367	3704	4057	4427	4814
CHP	4,442	4,472	4,502	4,532	4,562	4,592	4,622	4,652	4,682
Marine	11	12	14	16	19	23	26	30	35
Hydro	541	541	541	549	549	549	549	549	549
Total	10503	10700	11117	11483	11910	12303	12713	13139	13583
									2503

Microgeneration Capacity (MW)	2012	2013	2014	2015	2016	2017	2018	2019	2020
Solar PV	1,484	1,989	2,447	3,084	3,694	4,478	5,233	6,052	6,941
Hydro	32	50	68	86	105	124	144	164	184
Wind	100	143	182	221	261	301	341	382	423
Total	1616	2182	2696	3391	4060	4903	5718	6598	7549

Table 1

[14] Future Energy Scenarios document http://www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios

In the 2013 FES, National Grid have defined micro-generation as generators below 5MW (the DECC Feed in Tariff (FITs) level).

The 2013 FES also contains demand projections. These are gross demand projections (i.e. embedded and micro-generation are considered to be generation rather than negative demand). This is shown graphically in Figure 7 (2013 FES Forecast Gross GB ACS Peak Demand). Peak demand relates to the expected demand at Triad and therefore the HH demand charging base.

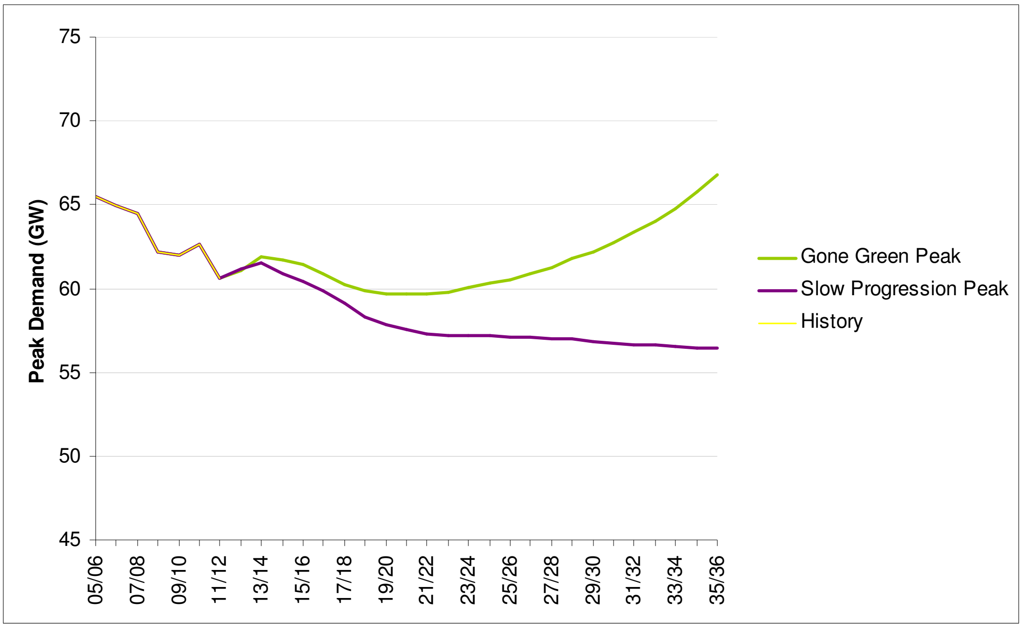

Figure 7

We have used this information to estimate the net GB peak demand that would be used as the basis for setting TNUoS demand charges. This has required us to set an output for generation during Triad periods (i.e. times of peak demand). National Grid does not have metering information for the majority of embedded generators and hence to understand likely outputs we have set generation as follows:

- Solar output has been set to zero as Triad demands occur during periods of darkness;
- Other intermittent plant has been set to 5% output as this is consistent with planning assumptions made in the NETS SQSS for peak demand periods;
- Conventional plant is uniformly scaled to meet peak GB demand.

Figure 8 shows how, on this basis, the output of all embedded generation (i.e. including micro-generation) during peak demand periods as a percentage of gross GB peak demand could change through to 2025.

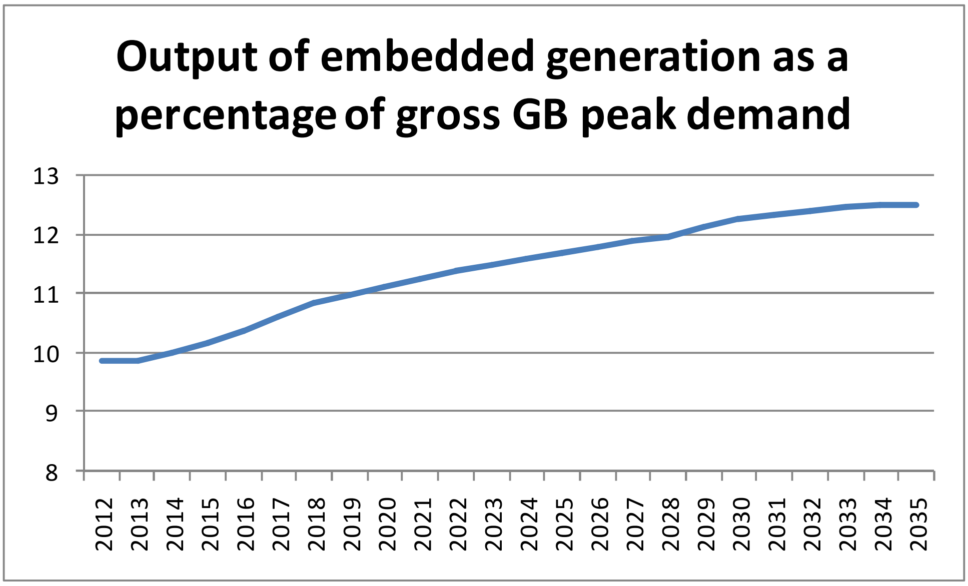

Figure 8

Using this methodology, in 2013/14 the forecast embedded generation output (including micro-generation) at peak would be around 6.1GW across GB. If this output was distributed evenly around GB, this would have a value, in terms of demand TNUoS avoidance, of around £155M per annum. In terms of avoided generation TNUoS charges this would equate to approximately £60M per annum. It is worth remembering that National Grid, through TNUoS charges, collect the maximum allowed revenue for all Transmission Owners, and hence, if the embedded benefit did not exist, this £215M would simply be redistributed amongst TNUoS charge payers.

4.4 What is the volume of small transmission connected generation projects?

There are currently 25 generators connected at 132kV in Scotland with a capacity of below 100MW. Additionally there are 5 offshore windfarms with a capacity of below 100MW connected at 132kV. All these generators (with a combined capacity of around 1450MW) are in receipt of the small generation discount arising from licence condition C13. In 2013/14 the Small Generators' Discount was valued at approximately £7.55/kW, with an overall impact of around £10.9M. It is recovered from demand customers on a non-discriminatory and non-locational basis and in 2013/14 was comprised of £0.193724/kW on the demand tariff and 0.027027p/kWh on the energy consumption tariff.

4.5 Comparison of charges faced by distribution and transmission connected generation

One of the drivers for the review of embedded generation charging arrangements was the perceived discrepancy between the treatment of small 132kV connected generation in Scotland (transmission connected) with similarly sized 132kV connected generation elsewhere in GB.. 132kV connected generators smaller than 100MW in England and Wales will not face transmission charges, as they would be considered to be distribution connected, whilst those in Scotland will.

In this section we compare the network charges faced by those small 132kV connected generators in Scotland with distribution connected generators.

Following advice from the Focus Group, this comparison covers both connection and wider network charges. This is because differing charging methodologies may cover different elements of a connection within their charges. For example, transmission connection charges are 'super shallow' in that any asset which can be considered to be infrastructure is not taken to be connection, and hence many transmission connected generators do not pay connection charges. It does not cover operational charges such as BSUoS.

Network Charges Faced by Small 132kV Transmission Connected Generation in Scotland

Small 132kV generators in Scotland pay similar transmission charges to all other generators connected to the GB transmission system. Excluding BSUoS charges, these may include:

- Connection charges – These are not paid by all small 132kV connected generators in Scotland, only those which have transmission assets solely for the use of that generator. In 2013/14 revenues collected from connection charges paid by these generators are estimated to be around £2.3M.
- TNUoS local charges – These are the charges that aim to recover the costs to the infrastructure assets connecting a generator to the main interconnected transmission system (MITS). These are not paid by all small 132kV connected generators in Scotland. In 2013/14 revenues collected from these charges is estimated to be around £1.2M.
- TNUoS wider charges – These are the charges that aim to recover the costs of the MITS and are paid by all small 132kV connected generators in Scotland. They are comprised of a locational element and a residual element. In 2013/14, the revenue collected from total wider charges for these generators is around £19.2M, of which around £4.3M is collected from the residual element.

Additionally these generators are in receipt of the small generators discount valued at approximately £7.55/kW.

A summary of these charges are shown in Table 2 below

2013/14 Tx charges for Tx connected generation in Scotland	Average (£/kW)	Max (£/kW)	Min (£/kW)
Connection charge	£2.62	£13.73	£0.00
Local charge	£1.31	£4.90	-£0.87
wider locational charge	£20.71	£25.44	£8.03
wider residual charge	£4.81	£4.81	£4.81
Small generators discount	-£7.55	-£7.55	-£7.55

Table 2

Network Charges Faced by 132kV Distribution Connected Generation

In England and Wales, where 132kV is generally a distribution voltage, generators connected at 132kV are liable for generation charges. Additionally licensable generators connected at 132kV with a capacity of equal to or greater than 100MW are required to have TEC[15] and therefore pay TNUoS charges.

Distribution charging methodologies are ‘common’ across all fourteen DNO areas. The CDCM charging methodology was implemented in 2010 for LV and most HV connected generation. The EDCM charging methodology was implemented in 2013 for all EHV (including 132kV) and some HV connected generation. On this basis a comparison was carried out predominately on the EDCM charging methodology, as this related to similarly sized generation to those small generators connecting at 132kV in Scotland.

UK Power Networks described these methodologies in further detail to the Focus Group[16]. Initially National Grid focused on a ‘bottom up’ approach to comparing distribution charging elements with transmission charging elements. It was noted by the Focus Group that these methodologies, whilst both based on load flows and incremental costs, were very different. It was therefore decided to take a ‘top down’ approach to the comparison. It was also decided that the comparison should consider both connection and TNUoS charges.

Ofgem, in their 2012 consultation on charging methodology for higher voltage distributed generation[17] produced an assessment of the distribution of net charges faced, or in some cases paid to, embedded generation under the proposed EDCM methodology. The results of this assessment are shown graphically in Figure 9. The average annual charge faced appears to be approximately £1/kVA, with the majority of generators in the range £-2/kVA to £4/kVA.

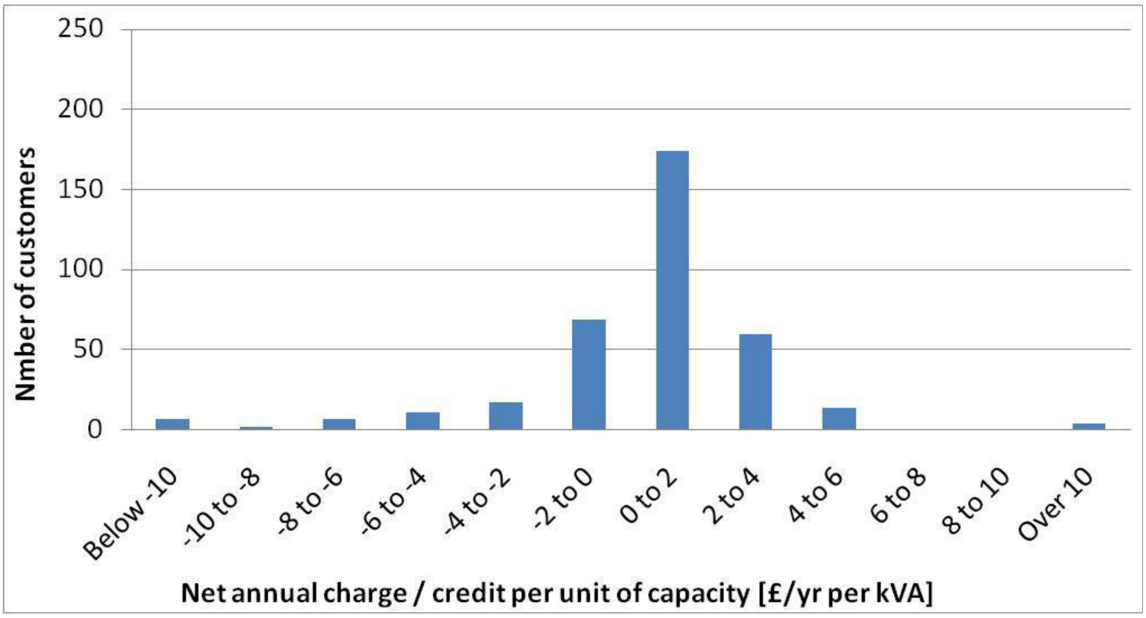

Figure 9

In addition, distribution connected generators pay upfront connection charges. National Grid understands that these charges are deeper than transmission connection charges (which are annuitized and collected on a depreciated basis over the asset lifetime).

[16] Network charges faced by distribution connected generation – 18th June http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/

[17] EDCM impact assessment https://www.ofgem.gov.uk/ofgem-publications/43901/edcm-export-aug-12-consultation.pdf

National Grid attempted to establish a typical range of connection costs for embedded generation based on indicative calculators and statements provided on the DNO websites. On presentation to the focus group, there was a general consensus that this did not reflect the costs faced by new projects. A more representative cost of £147/kW (a one off cost) was proposed by a focus group member based on their experience of historic projects. The confidential nature of an individual project does not allow publication of specific scheme details and hence why only a representative value is provided.

The Electricity Distribution Annual Report[18] published on the Ofgem website and its supporting data file indicated that, during financial year 2010/11, 789MW of embedded generation connected to the 14 GB distribution networks, including photovoltaic and domestic CHP, at a cost of £26.62m. We have used these values to calculate an annuitized connection charge for generation projects.

We have assumed that domestic generation projects such as photovoltaic and domestic CHP connections do not incur significant distribution connection costs and therefore we have removed an estimated volume of these generators from the calculation Based on the number of reported domestic generation connections, and assuming they have an average capacity of 3kW, we have estimated that there is about 42MW (13,975 connections x 3kW) of domestic generation within the reported total. This has then been subtracted from the total volume of connected generation (i.e. 789MW) to give a connected capacity of 747MW that gives rise to the quoted £26.62m cost.

To allow a comparison with National Grid connection charges this has been annuitized via the transmission connection charging methodology and assuming an average depreciated cost (i.e. straight lined) over the 40 year cost recovery period. On this basis, and converting into 2013/14 prices this gives an average annuitized distribution connection charge of £2.08/kVA.

The experience of a Focus group member was that distribution connection charges, when annuitized, gave a higher value for distribution connection charge of around £7.60/kVA. We would welcome any additional evidence providing more detail on distribution connection charges to further inform our thinking.

Q1 Do you have any additional evidence regarding distribution connection charges for generation connections and in particular 132kV connections?

4.6 Cost of avoided transmission infrastructure investment at GSPs

At the majority of grid supply points (GSPs) where demand is taken off the transmission system, there can be a benefit from embedded generation as it offsets the need for reinforcements arising from increases in this demand. Such reinforcements occur local to the GSP. A significant proportion of these costs are covered by connection charges, and it is only the infrastructure costs which would be liable to be recovered via TNUoS charges.

The approach to determine a unit cost of avoided infrastructure reinforcement cost due to demand reinforcement at a GSP was to calculate an average annuitised cost of that infrastructure

[18] Electricity Distribution Annual Report, Ofgem, https://www.ofgem.gov.uk/publications-and-updates/electricity-distribution-annual-report-2010-11

reinforcement and divide it by the average capacity delivered by a supergrid transformer (SGT). For the avoidance of doubt, this approach does not include the cost of the SGT itself as these are typically treated as connection assets and are therefore paid for by the DNOs under connection charges.

A total of eighteen NGET schemes were assessed from their RIIO-T1 price control submission and the spread of infrastructure costs can be seen in Figure 10 below.

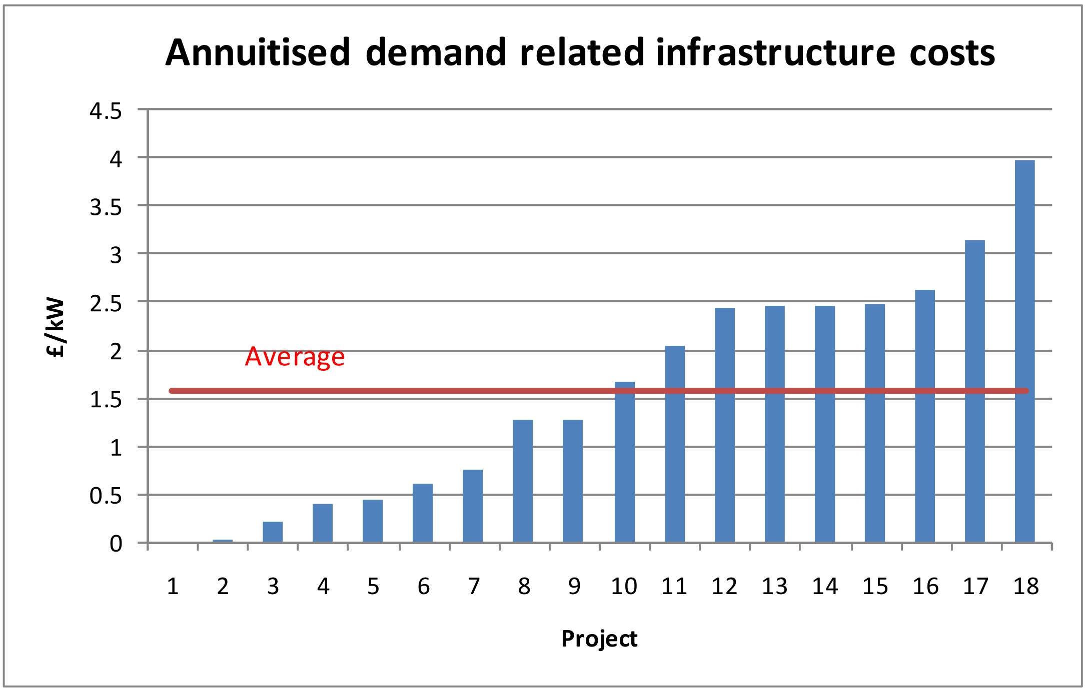

Figure 10

The average annuitized cost was determined as £1.58/kW in 2012/13 prices (£1.62 in 2013/14 prices). This is comparable with previous analysis in 2009/10 where the equivalent price was £1.47/kW.

4.7 Exporting GSPs

GSPs have traditionally been considered as importing power to the distribution network in order to meet demand. With increases in the volume of embedded generation, a number of GSPs have started to export power back onto the transmission network.

To assess the number of exporting GSPs, we have performed analysis based on operational metering data. It should be noted that NGET's operational metering, whilst adequate for real-time flow management of the transmission system, is not validated to the same degree as the commercial settlement meters and thus provides indicative information only.

For this analysis, three conditions were considered:

- GSPs that export at any point over the year;
- GSPs where the MW export exceeds the maximum import; and

▪ GSPs which export over the Triad peak demand periods.

The rationale behind looking at GSP that export more than they import was that these GSPs were most likely to trigger transmission network reinforcements in order to cope with the increasing levels of embedded generation. The outcome of this analysis is shown In Table 3 below:

Percentage of exporting GSPs

Year: 2012 / 13	**Scotland**	**E & W**	**GB Overall**
Exp. > 0MW	37%	22%	28%
Exp. > Max. Imp.	17%	4%	9%
Exp. over Triad	10%	3%	6%

Table 3

Whilst the percentage of GSPs that export in Scotland is higher than that in England and Wales, it is also clear that exporting GSPs is a GB wide issue.

Analysis was also produced to understand how often over a year a GSP would export, and the results are shown in Figure 11.

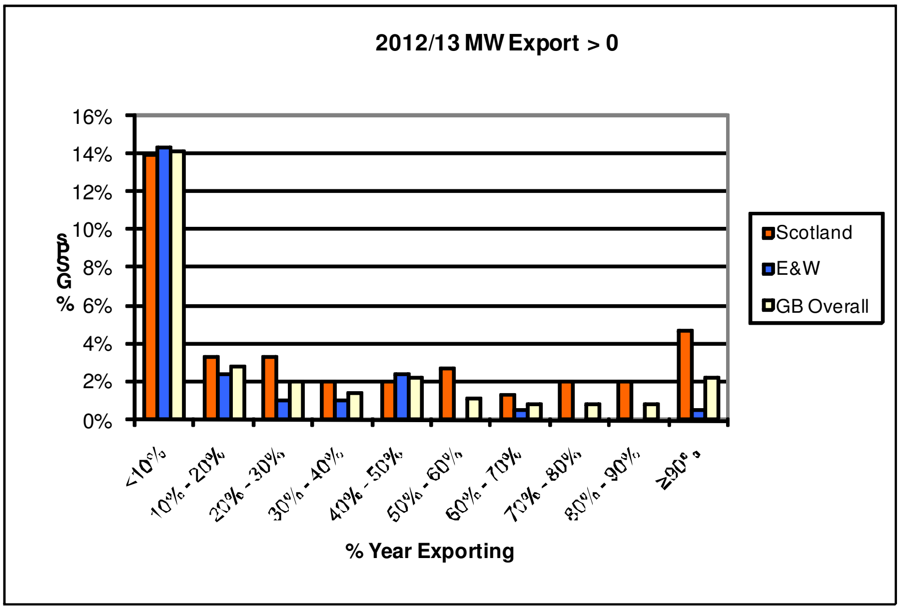

Figure 11

The Focus group has expressed interest in understanding whether the number and frequency of exporting GSPs has changed since BETTA. We have therefore assessed the percentage of GSPs in 2009/10 which either exported at any point over the year, or where the MW export exceeded the maximum import, or which exported over the Triad peak demand periods. These are shown below alongside the 2012/13 values in Figure 12, Figure 13, and Figure 14.,

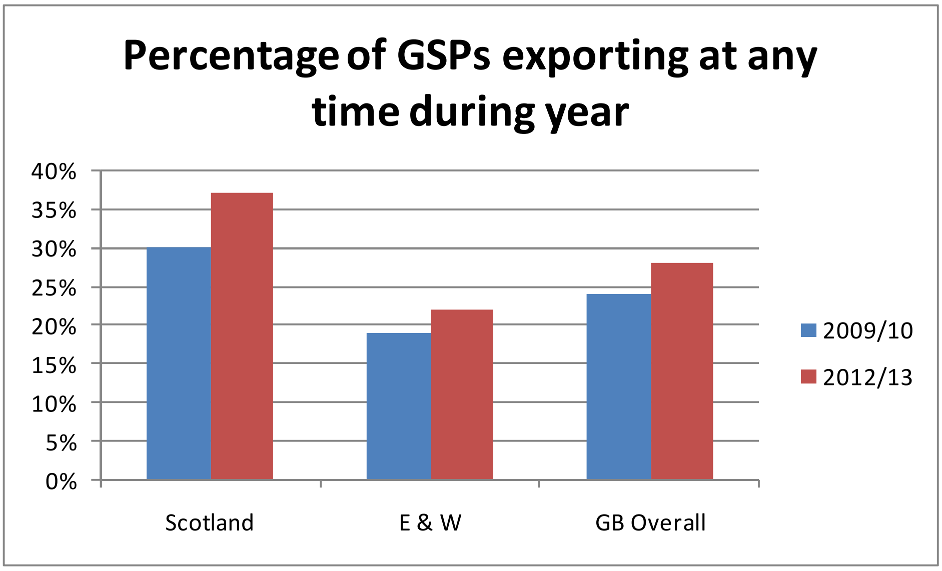

Figure 12

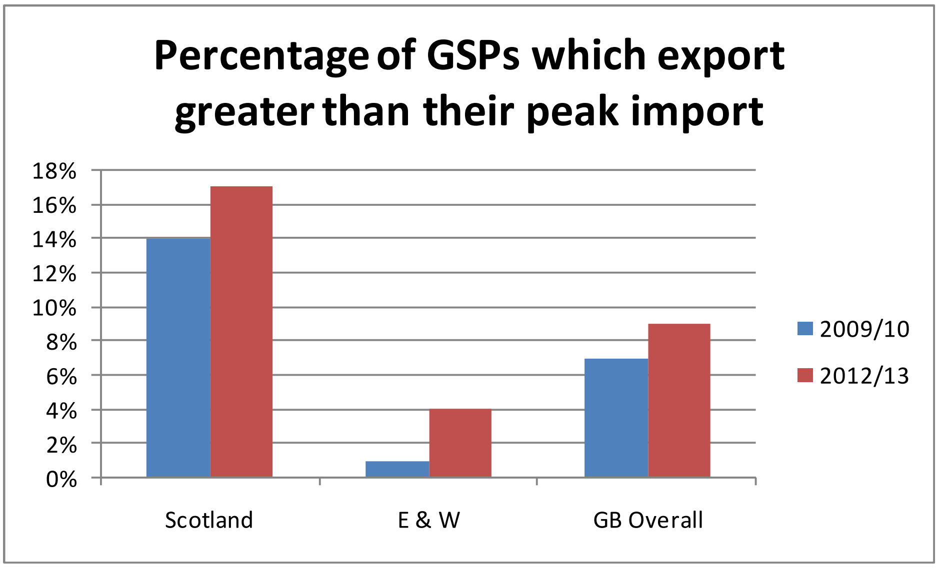

Figure 13

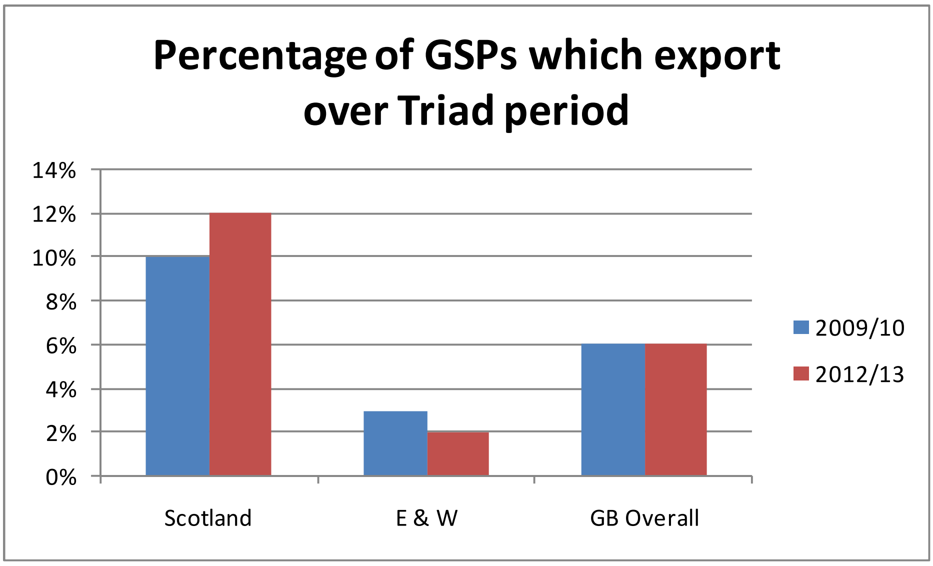

Figure 14

5 Focus group discussions

5.1 Focus group to review embedded generation benefits

National Grid established an informal industry focus group in May 2013 to review the appropriate treatment of embedded generation within its charging arrangements. The aims of the focus group were addressed at the initial meeting and broadly covered the following areas;

a) Review proposals previously developed under GB-ECM-23 and whether there are other options that can be pragmatically implemented;

b) Review impact of Transmit / CMP213 on the proposals

c) Consider whether there is any interaction with DNO Charging Methodologies

d) Consider the potential proposals against the applicable CUSC objectives

e) Identify potential consequential changes to other industry documentation and codes.

<u>Focus Group members</u>

Name	Company	Role
Andy Wainwright	National Grid	Chair
Jade Clarke	National Grid	Technical Secretary
Iain Pielage	National Grid	Member, Transmission company
Dena Barasi	Ofgem	Observer
Adam Lacey	Ofgem	Observer
Tim Russell	Russell Power, representing Renewable Energy Association	Member, Renewable generation
Guy Phillips	EON	Member, Supplier
Colin Prestwich	SmartestEnergy	Member, Independent supplier
Christopher Granby	Infinis	Member, Renewable Generation
Tim Rotheray	Combined Heat & Power Association	Member, Trade association
Jonathan Graham	Combined Heart & Power Association	Member (alternate), Trade association
Oliver Day	UK Power Networks	Member, DNO
Patrick Smart	Renewable Energy Systems Ltd	Member, Renewable Generation
Graham Pannell	Renewable Energy Systems Ltd	Member (alternate), Renewable Generation
James Anderson	Scottish Power	Member
Carys Rhianwen	Centrica	Member
Alan Goodbrook	Good Energy	Member, Independent supplier

Scope of the focus group review

Initial focus group discussions centred on the scope of the review and the factors that needed to be considered. To create some structure around these discussions, it was decided by the focus group that a list of parameters and areas in scope for discussion should be created before progressing to any discussion of specific topics. National Grid therefore drafted a list of parameters and areas for discussion which was split up into a number of sections to aid clarity. These are described further below.

Electricity Transmission Charges affected

Given the broad scope of the review, the Chair expressed a need to reduce the scope to a manageable level, and suggested that the review should initially focus on the TNUoS charging methodology. A number of reasons were cited for this proposal;

- Any benefit arising from transmission losses was significantly smaller than that from TNUoS and BSUoS charges. The focus group requested updated analysis to support this view which was presented at a later focus group meeting on both a capacity and commodity basis.
- CMP201 (Removal of BSUoS Charges from Generation) seeks to significantly alter the charging base for BSUoS charges, and is currently being assessed by the Authority. It was therefore felt appropriate to park consideration of the embedded benefit arising from BSUoS charges until the outcome of this proposal had been determined.
- The C13 issue is currently managed via the TNUoS charging methodology (CUSC 14.14.9) and therefore any proposal should consider the embedded benefits arising from this methodology first and foremost.

There was general focus group support for this approach.

Principles: transmission charging (CUSC) and Ofgem

The Chair noted that the review should focus on measuring the embedded benefits against the CUSC objectives in relation to electricity transmission charging. These are;

- that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;
- that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) Incurred by transmission licensees in their transmission business and which are compatible with standard condition C26 (Requirements of a connect and manage connection);
- that so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

In addition it was noted that the review should also consider Ofgem's broader remit of considering the impact against sustainability.

Focus group views of the apparent defect

At the start of the process, the focus group spent some time discussing the apparent defects that the review was intending either resolve or improve. There was a general agreement within the focus group that the following two remits were areas for consideration when discussing potential defects.

- Cost reflectivity of transmission charges on distribution connected generation.
- Impact of transmissions charges on competition between transmission and distribution connected generation.

These were primarily based on the charging objectives of cost reflectivity and facilitating competition. These were presented to the focus group by the Chair for their views on whether the remits should be classed as defects themselves.

Most of the focus group felt that there was no clear defect or impact on the embedded benefit within the two apparent defects presented and preferred the term 'remit' over 'apparent defect'. Some members believed that cost reflectivity should take priority over competition and that by addressing cost reflectivity it should in turn address competition. A view was expressed that applicable CUSC objective b (cost reflectivity) should always be considered first as competition can only be considered in a broader sense. Therefore the review should focus on cost reflectivity.

There was general support that, even if there were no apparent defect, that cost reflectivity of the embedded benefit could be improved. Exporting GSPs was highlighted as a defect by a number of group members and most thought that addressing this could in turn help improve cost reflectivity.

A number of members queried whether transmission and distribution connected generation were in competition. Two members believed that charges such as TNUoS were intended to be long run charges and therefore were not factored into generation operational decisions, but rather long term investment decisions. On this basis, they believed it to be rare that network charges influence the siting of generation projects. It was argued that other factors such as land and labour costs and acceptability for planning consent were also worthy of consideration, but the Chair noted that this forum was to discuss electricity transmission charges.

<u>Primary factors for consideration</u>
A number of factors were considered of primary importance to the focus group. These were:

- Net / Gross – Previous reviews of the embedded benefit had considered whether charging should be based on gross or net demand, and it was felt that this review should also consider this.
- DNO / Supplier - Previous reviews of the embedded benefit had considered whether charging should be based on arrangements involving either a DNO or a Supplier acting as an agent, and it was felt that this review should also consider this
- Residual / Locational – TNUoS tariffs are comprised of residual and locational elements. The Focus Group believed that the effect of each of these elements should be considered.

<u>Factors: out of scope</u>
The Focus Group agreed that certain areas would be out of scope of the review. These included the TNUoS charging methodologies for generation and demand other than their application, which would minimise interaction with CMP213 (Project TransmiT) and also rule out of scope any review

of Triad arrangements. As this forum was to discuss the transmission charging methodologies, changes to the distribution charging methodologies were also agreed to be out of scope. Finally the Focus Group agreed that operational issues regarding the management of access for embedded generation would be out of scope.

Implementation issues
The Focus Group identified two issues that it believed to be related to implementation. The first of these was in regard to data requirements, where a differing charging model may need a different metered data source or IS system. The second related to the appropriate level of notice that would be required for any change to the level of embedded benefit. In both these cases there was majority support for their consideration as implementation issues only, and therefore appropriate consideration would be as part of any ensuing formal CUSC modification process.

5.2 Does embedded generation use transmission?

The Chair had previously raised the question whether embedded generation should pay for transmission and whether charging this would be more cost reflective. He believed the key to answering this question was for the focus group to firstly understand to what extent embedded generation uses the transmission network. There were different views within the focus group when determining how embedded generation uses the transmission system.

There was a majority view that the extent to which embedded generation used the transmission system ought to be what determines how much they should pay towards it. Those focus group members believed that it followed that embedded generation should not pay transmission charges as they do not use the transmission system. This led on to a discussion around exporting GSPs and a potential situation where the large amount of embedded generation within a GSP would cause the GSP to export, therefore the embedded generation would technically be using the transmission system. There was a majority view by the focus group that net export of embedded generation at a GSP was using the transmission system and should therefore pay export related charges for the actual export.

As this occurrence would not involve all embedded generation across GB it was suggested that charging DNOs rather than all embedded generation would be more cost reflective and encourage DNOs to manage GSP exports which would in turn reduce transmission constraints and the need for GSP infrastructure reinforcement. It is important to note that “manage” does not always mean “reduce”. In the south of GB exporting GSPs may reduce the need for transmission reinforcement in exactly the same way as transmission connected generation.

National Grid noted that embedded generators are also benefitting in a similar manner to transmission connected generation in terms of both security and quality of supply and also access to market.

Whilst there was some agreement that embedded generation would make use of the transmission system in these manners it was noted that the different transmission functions should be weighted differently in terms of importance. Some focus group members believe that net transfers were significantly more important than the other functions, and that the other usages could be considered to be more incidental. These group members expressed the view that in the extreme if a GSP continuously had a net import or export of zero it was difficult to see how it was using or benefitting in any way from the transmission system. It was accepted by those who expressed this view that the situation was never likely to occur but an important concept in order to illustrate that usage of the transmission network was entirely related to net transfer on or off the transmission system.

The National Grid representative argued that embedded generation indirectly benefited from transmission through its arrangement with a Supplier who can access to the market to sell its power across GB. Some disagreed that this was a function of the TNUoS charges. They said that TNUoS charges should relate to the physical use of the transmission system i.e. the flows of power on it, not to any commercial contracts to buy or sell power. It was also noted that generally embedded generation has no firm access rights, which some believed affected their access to market.

The National Grid representative put forward the view that the level of redundancy built into the main transmission system in accordance with the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) provided a benefit to embedded generation. Other group members believed that the level of redundancy only provided any benefit in relation to actual or potential physical flows on the transmission system. The National Grid representative also suggested that there were broader quality of supply benefits such as the management of system frequency. Most members viewed security and quality of supply as being of primary benefit to demand consumers and that any benefit to embedded generation was largely incidental. A view was expressed that the NETS SQSS was solely in relation to 'keeping the lights on' which was strongly refuted by the National Grid representative on the grounds of its other considerations such as safety.

<u>De minimis level</u>
Whilst the Focus Group generally agreed that there must be a pragmatic de-minimis level of embedded generation which could be considered to impact on the transmission system, it was undecided what level would be appropriate. Options included;

1. >5MW This was felt to be consistent with the generation applicability in relation to Feed-in tariffs and the FES definition of micro-generation.
2. >1MW This would be consistent with other ongoing industry proposals such as Grid Code proposal GC0042.
3. >50kW. as this would be consistent with the Green energy act 2009.
4. All half hourly metered generation. This would most easily fit around the existing commercial arrangements for TNUoS charges, but could impact generation as small as 30kW.

5.3 Views on the embedded benefit arising from TNUoS charges

National Grid presented their views on how the TNUoS embedded benefit arose, and how it could be considered to be equal to the summation of demand and generation residual elements of the wider TNUoS charge. Several focus group members suggested that this should not be described as a benefit rather an 'effect'. It was later noted that on some supplier contracts this item would be separately listed as 'the embedded benefit', but on other contracts it may be listed as something else or incorporated within other contractual elements.

The Focus Group discussed the cost reflectivity of the embedded benefit at length. A view was expressed that the benefit was a cost reflective signal as it related via the allowed TO revenues back to a unit cost of transmission. The Chair stated that the derivation of the demand and generation residuals was simply to allow the correct TNUoS revenue recovery and therefore had no bearing on the unit cost of transmission. Other members of the working group believed that as the residual and locational elements of the tariffs for generation and demand together covered the total allowed transmission network revenue; all TNUoS elements together by definition covered the total cost of transmission.

National Grid presented their analysis on the actual benefit provided to wider transmission infrastructure. The National Grid representative explained that this was the cost of avoided GSP infrastructure investment (i.e. not including transformer costs that would be recovered through connection charges) and had been calculated using the NGET RIIO-T1 submission numbers. The averaged value was found to be £1.41/kW in 2012/13 prices. Whilst National Grid described this value as the de facto benefit, others believed this term misleading and preferred to use to term 'the cost of avoided GSP infrastructure'. It was noted that exporting GSPs would not necessarily trigger this saving as additional investment may be needed to manage additional exports rather than imports.

The Chair also illustrated the relationship between GB net demand and the demand residual, highlighting that, if allowed revenue remains constant, the lower the net demand the higher the demand residual will be (Figure 15). Hence increasing volumes of embedded generation will offset a greater amount of demand reducing the overall net demand hence increasing the demand residual as shown graphically below. The Chair believed this to be evidence of a perverse incentive for embedded generation as effectively the embedded benefit will increase the more embedded generation is connected. The Chair put forward that if the embedded benefit is to act as a cost reflective signal for embedded generation to connect, it should either be a fixed value or reduce as the amount of embedded generation increases, consistent with other incentive mechanisms. Others in the group disagreed with the description of the embedded benefit as an 'incentive mechanism', and saw it as rather a signal for embedded generation, or as largely an incidental effect of the TNUoS charging methodology.

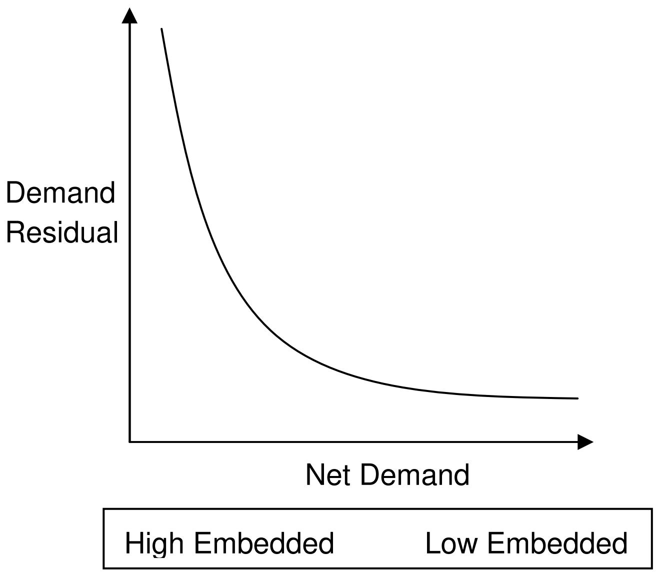

Figure 15

Whilst the focus group agreed that this was a true interpretation of the effect that changes in net GB demand has on the demand residual, there were differences in views related to whether this was perverse or whether as in the long term reduced net demand would reduce the allowed revenue and the demand residual would therefore not increase, it was cost reflective. It was noted that the cost of onshore transmission assets are recovered over a 40 year timescale, and therefore significantly limit any short to medium term reduction in allowed revenue.

5.4 Should demand be charged on gross?

The Workgroup noted that there have been a number of previous attempts to resolve the C13 licence issue, and that the principle of charging on net flows at GSPs or whether to charge on gross flows had been discussed at length previously. 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 and is the process used in the existing TNUoS methodology. Gross charging considers flows separately and would charge on both positive and negative demand bases.

This section focuses on the discussion related to demand charges. The question of whether embedded generation uses the transmission system and how much it should pay is dealt with in section 4.2.

This effect can be shown from Figure 16 below. Under net charging the demand residual would be charged to the 4MW of net demand, whereas under gross charging it would be charged to the 4MW of net demand and the 2MW of positive demand which has been netted off by 2MW of embedded generation i.e. 6MW of demand.

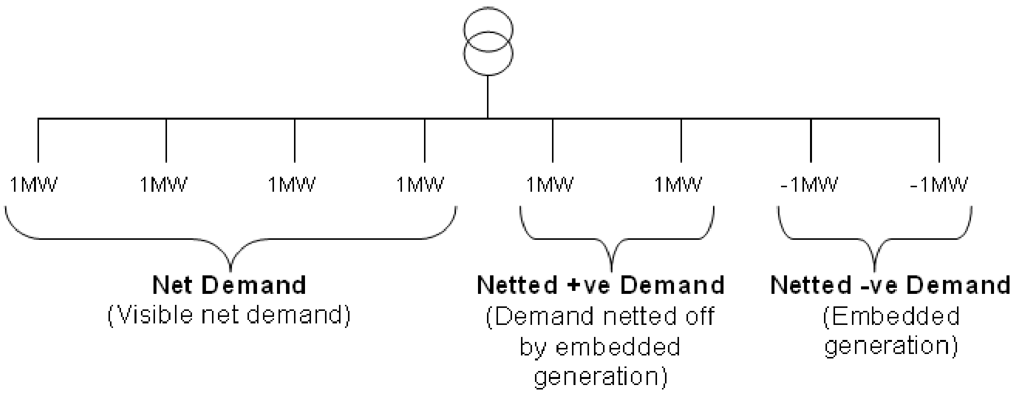

Figure 16

It was clear from the initial discussions within the focus group that this issue was still of importance to many attendees with a number of contrasting views as discussed below.

TNUoS charges are made up of locational (which send a cost reflective signal) and residual (which ensure correct revenue recovery) elements and it was generally accepted that the locational element could be charged on either net or gross as the signal would be roughly the same to all users. Any differences would be due to differences in charging bases and the constitution of generation and demand TNUoS zones. Therefore the focus of discussions was on the residual elements, and the charging bases for these elements.

<u>The case for net charging</u>
It was argued that general industry practice is to consider flows between connected networks on a net basis, and that a move to gross charging could be considered inconsistent with this approach. It was also argued that net flows onto and off networks trigger investment rather than gross flows and that if generation and demand were balanced locally then there would be a reduced need for transmission assets.

It was also commented that any embedded benefit was available to directly connected generation if it were to register with demand at the same location as a trading site.

The hypothetical situation was described where every GSP had sufficient embedded generation (with redundancy) to meet gross positive demands at all times. It was suggested that under these conditions there would be no need for a transmission system and this was used as justification for a net approach. However National Grid noted that the cost of onshore transmission assets are recovered over a 40 year timescale, and therefore significantly limit any short term reduction in allowed revenue. Most of the focus group had a preference for a net charging approach.

<u>The case for gross charging</u>
National Grid 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 explicitly made outside this consideration.

A second hypothetical situation was described, similar to the above, but where only the overall GB level of embedded generation met gross positive demand at all times, i.e. there was always the need for a transmission system to transfer power between importing and exporting GSPs. In this example, the net GB demand charging base under the current TNUoS methodology would be zero. Charging on a gross demand basis would resolve this issue. An alternative suggestion was made that this could also be resolved through consideration of exporting GSPs as generators with capacities, and using the sum of net importing GSPs as the demand charging base.

5.5 Comparison of transmission and distribution network charges paid by generation users

A view presented during discussions on whether embedded generation uses the transmission system was that transmission connected generation could similarly be considered to use distribution systems to deliver power to the end consumer. From this, there was discussion on whether all generation should pay transmission and distribution charges regardless of their connections.

It was also noted that, under the present TNUoS methodology, embedded generation receives a locational signal even through its netting with demand. There was significant support for this view in the Focus Group. The National Grid representative viewed that the issue was therefore due to the residual element of the charges, which arose simply to allow the correct revenue recovery. Other members of the working group believed that as the residual element of TNUoS charges was necessary for collection of the allowed revenue it was therefore directly related to the overall cost of transmission and therefore should not be paid by parties that did not use the transmission system.

The National Grid representative further postulated that all generation was in competition with each other, and therefore any differentiation in cost elements such as network charges could affect the marginal plant. Whilst this could be correctly justified for locational elements, the residual is basically an unavoidable charge on TNUoS charge payers and therefore could distort the marginal plant position such that potentially less economic embedded generation would run at the expense of some transmission connected plant. This could distort the market increasing the cost paid by the end consumer. Focus Group members suggested reviewing the 100MW licensed generator limit to address this concern and provide generators with increased connection choice.

Others disagreed with this view, seeing TNUoS charges as a long run signal not affecting operational market decisions. Their view was that embedded generation was not in competition with transmission connected plant. The majority of the group disagreed with the National Grid view on the basis that different groups of generators facing different charges was not anti competitive if those different charges related to the goods and services that those different groups of generators utilised and that those charges were established on a cost reflective basis[19].

Some members said a comparison of distribution and transmission charges was unnecessary as most generators did not have any realistic choice whether to connect to transmission or distribution.

However there was some level of agreement that both transmission and distribution charges paid by generation users contain non-locational elements that serve for revenue recovery purposes. If these elements seemed of a similar magnitude, then it could theoretically be argued that there would be a level of offset. It would follow that it may be reasonable to consider that the fact that transmission connected generation would pay TNUoS and embedded generation would pay distribution charges under the EHV Distribution Charging Methodology (EDCM) or Common Distribution Charging methodology (CDCM) methodologies did not hinder competition. It was noted that some embedded generators, of TEC in excess of 100MW, pay both sets of charges. It was also noted that the relative depths of distribution and transmission charging methodologies would also limit any comparisons that could be made.

As background, one focus group member presented on demand and generation charging under the Common Distribution Charging methodology (CDCM) and the EHV Distribution Charging Methodology (EDCM) within the first focus group meeting.

Initial comparisons focused on the elements within both charging methodologies. It was noted that the charges are constructed very differently, which could limit any comparison of elements. However, it was noted that the capacity element of EDCM charges seemed most closely related to

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19 For example, the fact that a wind turbine does not pay for coal does not mean that it is competing unfairly with a coal fired generator. Whether some users paying transmission or distribution charges and some not did or did not distort competition depended purely on whether those users did or did not utilise the transmission or distribution system, just as the non payment for coal by a wind turbine was not anti competitive if the wind turbine did not use any coal.

the residual element of TNUoS charges as this was a £/kW charge levied on a DNO area basis. National Grid then prepared further analysis of EDCM charging elements, and a discussion followed with a variety of views as to which elements should be compared.

The view was therefore expressed that a top down approach may be more appropriate with consideration of average charges paid under each methodology by generation users. The average 2013/14 TNUoS generation charge is £7.75/kW of which £4.81/kW is due to the residual. A focus group member presented the range of capacity charges for EDCM customers to the focus group as taken from the EDCM methodology consultation[20]. This highlighted that the highest percentage (48%) of customers pay £0-£2 / year per kVA. It was noted that these charges can change significantly between DNO areas and that some generator users receive credits rather than pay charges which was also the case in the TNUoS charging methodology.

Many Focus group members did not agree a suitable comparison between charging regimes could be made without comparing transmission and distribution connection charges, as there was a view that distribution connection charges are generally deeper than transmission connection charges, i.e. more assets are specifically charged back to generators under the distribution methodologies. National Grid agreed to further consider distribution and transmission connection charges. Proponents of this view said that any comparison must sum the totals of connection and Use of System charges for both transmission and distribution connected generation in order to get a fair view of the relative burdens of network charges on transmission and distribution connected generation.

5.6 Exporting GSPs

One of the items that some of the focus group believed to be of concern in relation to the TNUoS embedded benefit was exporting GSPs. Traditionally their perception was that the embedded benefit was paid to an embedded generator to reflect the offset cost of transmission that was not required due to their existence. If a GSP is reinforced on the basis of export capacity, there was a view within the group that it was not correct for it to receive the embedded benefit, and that the methodology could be improved in this area.

Others in the focus group believed that this issue was a broader issue concerning the TNUoS charging methodology and an area where an improvement could be made. These members felt that exporting GSPs needed addressing as they affected the transmission system like transmission connected generation and could either increase or decrease constraints on the transmission system depending on their location and could also trigger GSP infrastructure reinforcement costs (these members did not generally believe that importing GSPs would similarly impact on the transmission system). There was significant support for exporting GSPs to be charged for the net exports on a similar basis as transmission connected generation. The Chair noted that this belief was not directly related to the consideration of embedded benefits, and therefore commented that it may be more appropriate to be taken forwards as a separate modification proposal.

There was general agreement that exporting GSPs could trigger infrastructure reinforcement costs at those GSPs.

[20] https://www.ofgem.gov.uk/ofgem-publications/43901/edcm-export-aug-12-consultation.pdf

It was noted that currently National Grid only has supplier demand figures on a GSP Group basis, and that any effective cost reflective treatment of exporting GSPs would be better on a GSP basis. It was suggested that a potential way of resolving this issue would be through levying an exporting GSP charge on the DNO by calculating maximum export of a GSP over a 12 month period, with the DNO then passing on this charge. An alternative option suggested was that Suppliers could be charged on a GSP basis, or that the exporting issue could be considered at a GSP Group level. In such a situation it was suggested that exporting GSP groups could be charged TNUoS as generation users (i.e. paying the generation residual) with importing GSP groups being charged as demand users (i.e. paying the demand residual) This led to a discussion around stability and the potential step change of TNUoS charges if a GSP Group were to switch from importing to exporting and vice versa. It was noted that a transmission connected generation could pay demand TNUoS if taking demand over the Triad, but would still be charged generation TNUoS based on its TEC.

Discussions followed as to what was meant by an exporting GSP, i.e. was it any GSP which exported during a settlement period during the year, during Triad, or another measure. The Chair believed, for charging purposes, an exporting GSP should be limited to a GSP which has a higher export during a settlement period than its maximum import during a charging year, as this determines whether any GSP infrastructure reinforcement would be on the basis of import or export. Others disagreed with this view.

5.7 Options for change

The National Grid representative stressed that any CUSC modification proposal arising from the embedded benefits review should consider the broader cost reflectivity of embedded benefits contained within the TNUoS charging methodology accounting for the impact of embedded generation on such costs. This approach would be consistent with Ofgem's view presented in the Transmission Arrangements for Distributed Generation (TADG) Working Group Report[21]. To that end he asked the Focus Group for any views or thoughts on ideas that could be taken forward.

One Focus Group member presented a number of views on incremental changes to the TNUoS charging methodology that he believed would improve cost reflectivity. These did not necessarily directly relate to the embedded benefit (although the proponent thought that they would improve the cost reflectivity of the current net charging arrangements) or resolving the C13 licence issue. Ideas included increasing the resolution of the locational signal, charging generation based on the same time periods as demand, consideration of other technical aspects that might drive costs in addition to load flow, management of exporting GSPs and abolition of discrimination of the basis of size for embedded generation. The proponent of these views thought that if taken forward the cost reflectivity of net charging would be further improved although these improvements in cost reflectivity may not be justified in being taken forward given the changes necessary to implement them. Other focus group members agreed with these views.

There was a level of support within the Focus Group for developing options to better reflect the impact of exporting GSPs on the transmission system in the TNUoS charging methodology.

[21] https://www.ofgem.gov.uk/ofgem-publications/55753/070730tadgcoveringletterfinal.pdf

It was noted that any proposal would need to consider the impact on transmission access arrangements and changes would need to be commensurate with the level of access rights users had. It was cited by one Focus Group member that embedded generation had lower access rights and would receive neither Balancing Mechanism payments nor compensation for loss of transmission access when instructed to disconnect under Emergency Instruction from the System Operator (NETSO). The Chair noted that whilst this was a factor that needed consideration, it was often impractical to take actions to manage transmission constraints using embedded plant. This was for a variety of practical reasons including the lack of a direct interface between the generation and the NETSO, and also the number of individual generators that would need to be contacted and the timescales involved.

There was a view that the 132kV system in Scotland should be re-designated as distribution given the amount of upgrading to 275kV and 400kV that had occurred in Scotland since BETTA. The Chair noted that the Focus Group was established to review charging arrangements, and that such a step would be a more fundamental reform.

The Focus Group discussed options in relation to Agency models and whether Suppliers or DNOs would be better placed to administer an embedded benefit payment scheme. Currently Suppliers are charged on a GSP Group basis, whilst DNOs are not involved in the TNUoS charging process. However there is a greater refinement of information in relation to DNOs such that the relationship between National Grid and DNOs works on an individual GSP basis. DNOs are also more able to respond to a cost reflective signal. There was a general recognition of these points and acceptance that charges and payments via DNOs could be more cost reflective, but would likely require more industry reform.

The National Grid representative restated his earlier presented views that there would need to be some level of gross charging in order to more explicitly define the embedded benefit. It was his view that improvements of the cost reflectivity of this benefit could only be made if it were made more explicit. Others in the focus group disagreed with this view.

<u>Focus Group views on how to resolve the C13 Issue</u>
A view was expressed within the focus group that National Grid should focus on the development of a proposal to simply resolve the C13 licence issue which allowed for National Grid to discount the use of system charges for sub-100MW generators connected at 132kV in Scotland and in offshore waters on a temporary basis. This followed a discussion on Focus Group member views on how to improve the TNUoS embedded benefit and whether there was even a defect to be resolved. Many Focus Group members did not believe there was a defect to be resolved, and the Chair therefore asked the Focus Group for their thoughts on a potential permanent solution to C13.

A variety of views were received. Some focus group members believed they did not know enough about the C13 issue to comment whilst others suggested that the small generators' discount should simply be removed.

There was some support for a tapering or extension of the benefit, and that it should not be extended to new generation projects. One Focus Group member thought that simply removing C13 would not be a viable solution and whatever solution is proposed, it should be wholly justified.

A working group member believed that charging TNUoS for embedded generation would not solve the C13 issue as it would simply create an “English and Welsh” 132kV connected generator problem as these generators would pay both TNUoS and DNUoS whereas Scottish 132kV connected generators would only pay TNUoS.

In summary the following options were put forward for potential resolution of the C13 issue;
- Remove the C13 discount from April 2016 or another justifiable date.
- Enshrine the existing C13 discount into the TNUoS charging methodology.
- Taper existing benefit to a fixed value which in real terms would reduce over time.
- Retain existing C13 discount for existing applicable generation, but close it to new projects.

6 Potential options and next steps

6.1 Introduction

This section considers the range of options that could potentially address any discrepancy between the treatment of small transmission connection generation and embedded generation and also potentially improve the cost reflectivity of the embedded benefitarising from TNUoS charges. It is important to note that, at this stage, all options remain available and, by publishing this report, National Grid is seeking additional evidence and stakeholder views.

We believe that all generation, whether transmission or distribution connected, is in competition to supply the end GB consumer either directly or via a supplier intermediary. Whilst it is important that cost reflective charges are applied on generators to recognise their impact on network development, it is important that where there are differing methodologies, this does not translate into the development of less efficient generation and ultimately raise the cost of electricity for the end consumer.

6.2 Option 1 – Treatment of C13 licence issue alone

There was support within the industry focus group for enduring management of the time limited C13 licence condition alone, without the requirement for a broader review of embedded charging arrangements. A number of potential options were raised by the group:

- Remove the C13 discount from April 2016 or another justifiable date.
- Enshrine the existing C13 discount into the TNUoS charging methodology.
- Taper the existing benefit to a fixed value which in real terms would reduce over time.
- Retain the existing C13 discount for existing applicable generation, but close it to new projects.

The current 'small generators discount' seeks to provide an offset to the TNUoS charges paid by a small transmission 132kV connected generation through a generic proxy term in licence condition C13. It is there to recognise the difference in treatment from a similarly sized generator connected to a 132kV distribution network in England and Wales. Since its introduction in 2007 there have been several relevant changes to industry structures, chiefly:

- the establishment of common methodologies for distribution use of system charges. This development will allow easier comparison between the network charges faced by a distribution connected and transmission connected generator.
- the development of offshore generation connections. This has widened the range of those generators qualifying for the 'small generators' discount.

It is our belief that in order to determine whether or not to continue with the C13 discount, or a variation thereof, a comparison between network charges faced by those generators connected to 132kV distribution systems and those connected to 132kV transmission systems is required. This will identify whether the C13 discount is set at a level which makes it a suitable proxy. As previously noted, because both transmission and distribution connected generation currently receive the locational signals associated with TNUoS charges, any comparison on network charges can be undertaken without this element. Therefore we believe that a reasonable charge comparison of average charges faced can be made as in Table 4 below.

£/kVA	Transmission	Distribution A	Distribution B
Connection charge	£2.62	£2.08	£7.60
Local charge	£1.31	£0.00	£0.00
DNUoS charge	£0.00	£1.00	£1.00
TNUoS residual charge	£4.81	£0.00	£0.00
Small generators discount	-£7.55	£0.00	£0.00
Overall charge (with small gens discount)	£1.19	£3.08	£8.60
Overall charge (without small gens discount)	£8.74	£3.08	£8.60

Table 4

Distribution A generation charges use distribution connection values derived from Ofgem's 2010/11 Electricity Distribution Annual Report whilst Distribution B charges use values derived informally from a focus group member's experience. Comparison of Transmission and Distribution A charges indicate that there could be merit in retaining a reduced small generators discount and enshrining it within the TNUoS charging methodology. However, comparison of Transmission with Distribution B charges suggests that the overall network charges faced by both sets of 132kV connected generation are broadly comparable without the need for the small generators discount and that the discount could be removed.

We therefore believe that further evidence is required to understand the range of connection charges faced by 132kV connected generation.

Q2 Do you have any additional evidence that would aid the comparison of network charges faced by 132kV distribution and transmission connected generation of capacity less than 100MW?

Additionally we are aware that generators connected at 132kV in England and Wales with a capacity greater than 100MW are required to pay both transmission and distribution charges. We believe that this is also an area of potential difference in treatment, and believe that a removal of the small generators discount would go some way to ensuring equitable treatment.

6.3 Option 2 – Better reflecting the impact of exporting GSPs on transmission investment

Our analysis presented in section 4.8 indicates a growth in the number of exporting GSPs since 2009/10 with now over a quarter of the GSPs in GB exporting at some point during 2012/13. There was recognition within the focus group, as discussed in section 5.6, that this was an area that could be potentially be improved within the TNUoS charging methodology.

Q3 Do you agree with the view that exporting GSPs is an area that could potentially be improved within the TNUoS charging methodology?

If the purpose of the embedded benefit is to recognise the reduction in transmission infrastructure investment, then it follows that if a GSP is exporting it is no longer reducing this investment. In these cases it is behaving similarly to a transmission connected generator. In section 4.6 we estimated the cost of GSP infrastructure investment to be around £1.62/kW in 2013/14 prices. Such a figure may be a reasonable proxy for the additional cost incurred at an exporting GSP as this relates to the cost of avoided infrastructure. It would therefore seem reasonable that this additional cost was passed through to embedded generators at exporting GSPs.

An alternative proposal would be to treat exporting GSPs as generators for charging purposes with a pseudo 'TEC' based on their maximum export during a year. There would appear to be a number of options to consider which GSPs, for the basis of TNUoS charge setting, are exporting. These options include:

- All GSPs which export above 0MW during any settlement period within a 12 month period.

- GSPs which export over the Triad period when demand charges are measured. This would be consistent with the need to develop GSP reinforcement for peak demand periods and would send a signal to reduce generation at such GSPs to prevent exporting.

- GSPs whose MW export during a settlement period is greater than their maximum MW import during a settlement period. This would be on the basis that such GSPs are reinforced on an export rather than import basis.

Presently, demand TNUoS charges are levied on suppliers on a GSP group basis. These GSP groups are set to DNO areas and therefore contain a large number of GSPs. Currently there are around 150 GSPs in Scotland and 200 in England and Wales. This means in England and Wales there are around 17 GSPs on average in each GSP group, and 75 GSPs in each GSP group in Scotland. National Grid does not have commercial metering information on an individual GSP basis, and does not currently have access to supplier information on such a basis.

If it is appropriate to reflect the additional cost on the transmission network of embedded generation at exporting GSPs, then we believe that there are two alternative mechanisms available;

- A supplier agency model. This would remain based on a GSP group granularity and could either be levied on the basis of an exporting GSP group or the number of exporting GSPs within a GSP group. Whilst such a methodology would be relatively straightforward to introduce within the current contractual framework, it would have limited cost reflectivity. It is also debatable whether a supplier could react to exporting GSP signals, and it is important that cost reflective signals are targeted to those users who can respond to them.

- A DNO agency model. This would be based on a GSP basis and would be levied on DNOs to be potentially passed through to generators connected at exporting GSPs (although this would require additional framework changes). This would require more industry reform than the supplier agency model, although precedent for such pass-through elements already exists in the 'Assistance for Areas with High Electricity Distribution Costs'[22]. However additional

[22] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Assistance-for-areas-with-high-distribution-costs/

metering information would also be required, and there would need to be consequential changes to the distribution use of system charging methodology. This approach would allow a much greater level of cost reflectivity with charges passed onto users who could respond to the signals.

Q4 Do you have any comments on the options raised above for the treatment of exporting GSPs within the TNUoS charging methodology, and do you believe there are any options that need further exploration?

6.4 Option 3 – Charging the demand HH residual on a gross basis

In section 2.3 we described how embedded benefits arise from TNUoS charges. This is primarily due to the avoidance of the residual element of the wider TNUoS tariff through netting of demand with embedded generation.

If the demand residual for HH customers were charged on a gross basis then Suppliers would be unable to net with embedded generation to avoid the demand residual. Under this option, the demand HH locational element would still be charged on a net basis as a separate tariff. Hence embedded generation would still implicitly receive a locational signal and would also not pay the generation residual element of TNUoS charges.

It is important that users receive the appropriate signals even if these are implicit. Therefore, as stated in the present methodology, demand charges should always be positive to ensure demand users are signalled to reduce their demand at peak periods (i.e. the Triad) and embedded generation are signalled to increase their output at peak periods.

The solid line on Figure 17 below shows the locational zonal demand signal, i.e. where 50% of zones have positive tariffs and 50% have negative tariffs. A first scalar is required to ensure that demand charges are collared at zero. However this scalar is not sufficient to allow full revenue recovery and therefore a further scalar is required (as shown by the top line). Under this option, the first scalar would be applied to net demand and the second to gross demand.

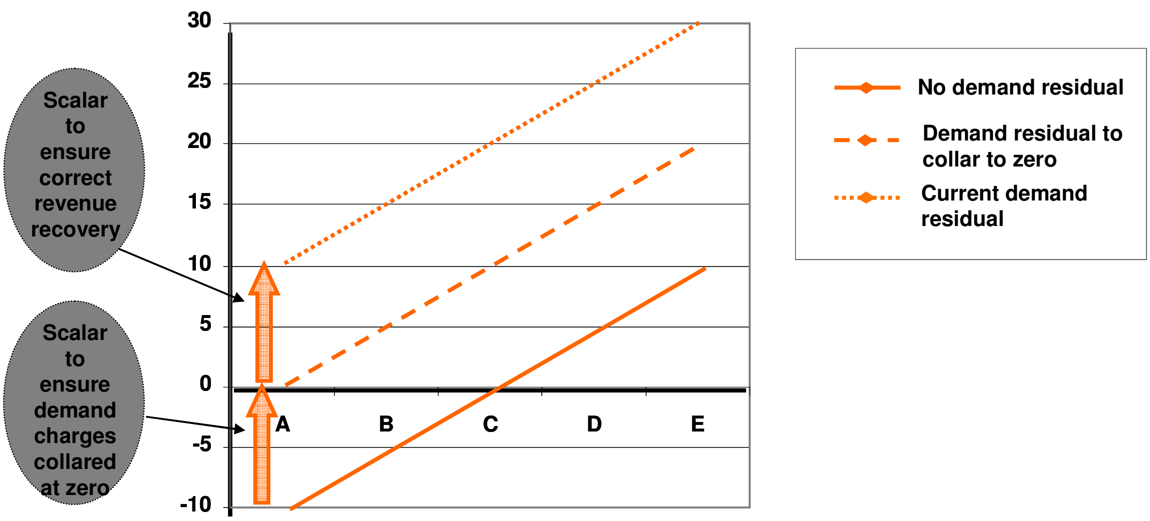

Figure 17

In terms of 2013/14 HH demand tariffs, demand zone 1 has the lowest tariff with an initial re-referenced tariff of -14.55£/kW. Under this proposed methodology an initial residual would be applied to all net HH demand to collar this tariff at zero (i.e. a residual of £14.55/kW). In 2013/14 the HH demand residual was calculated as £25.41/kW, so this smaller residual would result in an estimated shortfall in revenue collection of around £600M. This would be collected across an estimated gross HH demand charging base of 62GW (based on our estimation of embedded generation output at peak in section 4.3), giving a residual tariff for revenue recovery purposes of £9.81/kW. This element would not form part of the embedded benefit. On this basis the embedded benefit in 2013/14 would fall from £30.22/kW to £19.36/kW.

A potential alternative to this would be to collar the demand charge at the cost of avoided infrastructure reinforcement at a GSP rather than at zero. Our analysis has indicated that this is around £1.62/kW in 2013/14 prices. This would then ensure that all embedded generation received an appropriate signal to generate at periods of peak demand.

Q5 Do you have any comments on the option raised above for the charging of the HH demand residual for revenue purposes on gross demand?

6.5 Option 4 – Demand charging on gross and explicitly charging embedded generation

Under this option suppliers would be charged wider TNUoS on the basis of both embedded generation and gross demand rather than their net position. The Transport model flows would still be based on a net basis and locational signals would continue to be derived from this. However demand would be charged on a gross basis (i.e. all positive demand would be charged) and hence would receive both the locational and residual elements.

Embedded generation would also be charged wider TNUoS via Suppliers (i.e. there would be no requirement for a contractual relationship with National Grid). There are a number of sub-options for how this could be charged relating to both the locational and residual elements. With regards to the locational element sub-options include:

- An inverse demand locational signal. Treat embedded generation as negative demand and hence give them the inverse locational signal. This would retain existing 14 demand zones for embedded generation.
- A generation locational signal. Embedded generators would be treated as transmission connected generation and receive the same locational signal. GSPs would need to be allocated to generation zones, and Suppliers would need to identify embedded generation on a generation zonal basis. Under CMP213 (Project TransmiT) proposals this would then require embedded generation to have both a peak security and year round tariff, so a measure of their annual output to establish an Annual Load Factor (ALF) would be required.

Q6 Do you have any evidence to support any of the sub-options considering the application of the TNUoS wider locational element to embedded generation?

With respect to the residual element sub-options could include

- No residual element. Embedded generation would not pay either demand or generation residual.

- The generation residual element. Embedded generation would pay the same residual element as transmission connected generation on the basis that both use the transmission system in the same manner.

- A reduced generation residual element. Embedded benefit would pay a lower residual than transmission connected generation to reflect a reduced level of transmission infrastructure investment at GSPs. Our analysis has indicated that this is around £1.62/kW in 2013/14 prices. The generation residual element is currently £4.81/kW in 2013/14 prices.

Q7 Do you have any evidence to support any of the sub-options considering the application of the TNUoS wider residual element to embedded generation?

Q8 Do you have any other comments on the option to charge demand on gross and explicitly charge embedded generation?

7 How to Respond

This report forms part of our informal review on the embedded benefits arising from transmission charges. As part of this review we are interested in hearing your views and particularly any additional evidence you may have to support any of the views expressed in this report. We presented a spectrum of potential options and have posed a number of questions relating to these options. These are presented below and we welcome responses from stakeholders by 14th February 2014.

Q1 Do you have any additional evidence regarding distribution connection charges for generation connections and in particular 132kV connections?

Q2 Do you have any additional evidence that would aid the comparison of network charges faced by 132kV distribution and transmission connected generation of capacity less than 100MW?

Q3 Do you agree with the view that exporting GSPs is an area that could potentially be improved within the TNUoS charging metholodogy?

Q4 Do you have any comments on the options raised above for the treatment of exporting GSPs within the TNUoS charging methodology, and do you believe there are any options that need further exploration?

Q5 Do you have any comments on the options raised above for the charging of the HH demand residual for revenue purposes on gross demand?

Q6 Do you have any evidence to support any of the sub-options considering the application of the TNUoS wider locational element to embedded generation?

Q7 Do you have any evidence to support any of the sub-options considering the application of the TNUoS wider residual element to embedded generation?

Q8 Do you have any other comments on the option to charge demand on gross and explicitly charge embedded generation?

Please email your responses to: dave.corby@nationalgrid.com

Please note that information provided in response to this consultation may be published on National Grid's website unless the response is clearly marked "Private & Confidential". Evidence presented in a response marked "Private and Confidential" may not be able to be used to support a CUSC modification proposal. An automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential".

8 Glossary

The following terms are used within this report and this glossary is provided to aid the reader. It has been written as a guide rather than a set of formal definitions.

CDCM: The Common Distribution Charging Methodology (CDCM) is the Distribution Use of System (DNUoS) charging methodology for low voltage and some high voltage customers. It was approved by Ofgem in November 2009.

CUSC: The Connection and Use of System Code (CUSC) is the contractual framework for charging and connection to, and use of, the transmission system. It is subject to open governance arrangements meaning any CUSC party can propose a change. Ofgem can also allow non CUSC parties to submit change proposals.

DNO: A Distribution Network Operator (DNO) is the industry party responsible for the planning operation and maintenance of distribution networks. In Scotland, distribution networks are at voltages below 132kV, but generally in England and Wales onshore132kV systems are considered to be distribution networks also.

EDCM: The Extra High Voltage Distribution Charging Methodology (EDCM) is the Distribution Use of System (DNUoS) charging methodology for some high voltage and extra high voltage customers. It was approved by Ofgem in April 2012.

GB-ECM-23: GB-ECM23 was National Grid's 2010 review of embedded charging arrangements. It was put on hold as a result of Project TransmiT.

GSP Group: This is the zonal charging base for TNUoS demand customers. A GSP Group consists of a number Grid Supply Points (GSPs) which transfer electricity from the GB transmission system to a DNO's network or directly to a transmission connected load. There are currently at fourteen GSP groups in England and Wales which are analogous to DNO areas.

HH demand: HH demand is that demand metered on a half-hourly basis.

Licensable Generators: Those generators requiring a generation licence. Licensable generators with a capacity greater than 100MW are required to pay TNUoS charges.

NETS SQSS: The National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS) sets out the criteria (both onshore and offshore) used in the planning and operation of the transmission system.

NETSO: The NETSO (National Electricity Transmission System Operator) is the industry party responsible for the operation of the overall transmission system. This is currently National Grid.

Network Operators' Week 24 submission: The Week 24 submission is a Grid Code obligation for DNOs to provide National Grid on an annual basis forecast data relating to demand and embedded generation within each GSP or grouping of GSPs.
NHH demand: NHH demand is that demand which is not metered on a half-hourly basis.

TEC: The TEC (Transmission Entry Capacity) of a generator is the commercial capacity of that generator required to give it access to the transmission system and to allow it to participate in the wholesale market. TEC is used as the chargeable capacity of a generator for TNUoS charging purposes.

TO: A transmission owner (TO) is the industry party responsible for the construction and maintenance activities of a transmission network. TNUoS charges recover the allowed revenues of all onshore and offshore TOs.

Triad: The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 clear days, between November and February of the financial year inclusive. The Triad is used as the TNUoS demand charging based for half-hourly demand.