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Hannah Nixon
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By email: Project.TransmiT@ofgem.gov.uk
17th November 2010

Dear Hannah,

Project TransmiT Call for Evidence

RenewableUK and Scottish Renewables

RenewableUK (formerly the British Wind Energy Association - BWEA) is the trade and professional body for the UK wind and marine renewables industries. Formed in 1978, and with over 630 corporate members, RenewableUK is the leading renewable energy trade association in the UK, representing the large majority of the UK's wind, wave, and tidal energy companies.

Scottish Renewables is the representative voice for the renewable energy industry in Scotland, influencing the legislative, regulatory and financial framework to deliver the best possible conditions for the industry's growth on behalf of over 300 member organisations. The renewables industry is playing a crucial role in Scotland's efforts to tackle climate change and increase the nation's energy security, and must continue to do so in order to meet renewable energy and greenhouse gas emission reduction targets.

Introduction

The GB electricity system is undergoing an unprecedented paradigm shift in order to facilitate the UK Government's 2050 decarbonisation targets. Early decarbonisation of electricity by 2030 has been identified by the Committee on Climate Change as the most economic path to 2050. Post 2030 fuel switching from fossil fuels to low carbon electricity in areas such as heat and transport will accelerate. The 2020 renewables target for 15% of UK energy from renewables, which translates into over 30% of electricity from renewables, is an important step to the 2030 milestone.

In Project Discovery Ofgem has identified the need for about £200bn of investment over the next decade as a start to the decarbonisation process. The majority of these funds are for low carbon electricity generation. The cost of finance for these projects and hence the cost to the consumers can be influenced by certainty of costs and charges and by lowering financial burdens and risks in project development.

The current methodologies for charging and securitisation were developed in an era dominated by large transmission connected fossil fuel power stations. In the current paradigm with large investments in renewable energy and distributed generation, alongside the existing generation, a re-examination of the needs and signals in charging and securitisation - through Project Transmit - is welcome.

Scope

The scope of the comments in this document is limited to electricity and does not cover gas. With respect to electricity, Project TransmiT should include:

- user commitment (Final Sums and IGUCM),
- demand and generation,
- all transmission related charges including reach into distribution and private networks,
- transmission losses,
- Interconnectors,
- competitive position with the rest of Europe (including Northern Ireland) for imports and exports,
- BSUoS [1].

[1] Noting DECC's decision not to introduce locational BSUoS in relation to connect and manage

Cost Reflectivity

There are important financial and commercial linkages which underlie the transmission charging regime. Firstly companies operating and owning the transmission networks require an **income** to fund their activities known as "**cost recovery**". This income is a result of applying **charges** to users of the networks. Charges might take account: of the assets used; of access to the system and/or of use made of the assets. The cost of new **investments** in networks must be recovered either from increasing charges or increasing the number of users or both. Network investments are often "lumpy" and the most cost effective investment is not necessarily the minimum required for any new user, and so the charging system must be able to accommodate different investment provisions.

The term "**cost reflectivity**" is used in the charging arena; however it is a very open term. At the extremes it can mean either that a small portion of the true cost is reflected in the charge, or at the other extreme that much more than the true cost is reflected in the charge.

For example for a cost of X, a charge of 10% of X could be termed cost reflective as could a charge of 1000% X, yet these two charges are different by orders of magnitude and will have massively different impacts upon users - yet both are cost reflective.

The converse of cost reflectivity is that users will face the same charges regardless of the costs that they impose on the system as a result of their decisions or actions.

In considering cost reflectivity the impacts of a new user's action and resulting charges on existing users is important. Existing users' charges may fall or rise as a result of the new user's action, even when the existing users' access to the network, service received and use of the network are all unchanged. For example user A may take an action which results in the charge for user B increasing or decreasing even when user B has the same services, access, rights and usage as before user A's intervention.

RenewableUK and Scottish Renewables support some form of cost reflectivity as a cost signal, and the degree of cost reflectivity should be set at a level which avoids unintended consequences that would confer benefit to other users in a non cost reflective manner.

In Annex 1 we have provided some examples where cost reflectivity is not considered appropriate and where investment decreases rather than increases charges.

Generator response to changing charges

The charges are partly designed to influence users' behaviours; however there are limitations to the impacts of charging messages on generators' behaviours. A generator or project developer has some key decision points:

1. Whether to develop a project in a given location – with a typically 5 year lead time to financial close;
2. Whether to construct a project i.e. invest in the generation asset;
3. Some years later – whether to close, reduce its level of Transmission Entry Capacity, replant or refurbish the generating plant.

Changes to transmission use of system charges may trigger full or partial closure of a plant or result in an extension of its life but are unlikely to change the operating regime of a power station in the immediate period following the initial investment decision.

The incremental cost methodology aims to expose users (generators and loads) to locational differentials which reflect their impact on future investment costs. Users may choose from the 21 generation charging zones or the 14 demand charging zones across the country. However, the differential can also be impacted by a number of factors outside the control of any individual developer:

- Other generators can locate/ close/mothball in the same zone;
- A large consumer can close down or relocate;
- Demand can increase or large customer(s) appear;
- The generator can[2] be re-zoned into a different TNUOS charging zone;
- A major transmission reinforcement can be delivered.

Over the lifetime of any generation plant of typically between 20 and 40 years, these factors can drive changes in an individual generator's charge in ways which do not reflect the relatively stable actual costs of the network, made up as it is in great part by the sunk capital cost of the investment and relatively stable and predictable operational and maintenance costs. Importantly, any of the above changes can take place over the lifetime of a generation plant and materially impact upon the TNUoS charges for existing generators (and demand users) despite the relative inability of the generator to respond to changes in the price signal.

[2] Demand on the other hand cannot be rezoned as Zones are linked to DNO areas.

Stresses on current charging

The following sections identify a number of topics indicating that the current system of charging is under stress. Each of these issues should also be reviewed when assessing potential options for the future.

User Commitment

Developers welcome the Review of Sharing Arrangements for Final Sums Liabilities published by National Grid on 2nd July 2010 where Users are no longer required to secure wider works in the security period from the 1st October 2010 to 31st March 2011.

User commitment does not fall equally on all new generation development as the levels required depend on location and whether onshore or offshore.

Developers require certainty and stability regarding the levels of user commitment which they are required to provide and would welcome confirmation that removing user commitment for wider works will be incorporated into the enduring arrangements.

Developers already provide significant sums of “user commitment” in the form of at risk investment in projects over a significant period of typically five years prior to financial close. These investments include:

- Project management and FEED studies:
- Securing land / lease options:
- Resource assessments and monitoring:
- Environmental surveys and assessments:
- Preparation of planning application, Environmental Statements and Environmental Impact Assessments:
- Down payments to secure delivery of long lead items.

The current levels of user commitment, in particular ahead of financial close, are a deterrent to investment in developing projects, especially by smaller market participants, which has an adverse impact on competition.

Offshore charging

Under the current charging methodology, the development of offshore renewables and the associated offshore transmission networks results in significant reductions in charges for onshore generators, even if the amount of transmission used by onshore generators is unchanged. Ultimately, charges for onshore generation will fall to zero and then become negative overall.

We have illustrated this process in an example in Annex 2.

HVDC

Although National Grid is considering the basis for charging for HVDC network assets, the charging methodology published for April 2010[3] does not mention HVDC or how HVDC would be accommodated, despite the potential for this technology to be deployed as early as 2015[4].

HVDC may or may not have a significant impact on charges. As we illustrate in Annex 3, the effect of the HVDC links on charging has evolved over the last year. We note that the principles and objectives have not changed in that time yet it appears that very different charges can result under these principles and objectives.

This uncertainty over charging creates risk which will make projects more expensive to finance and increase costs to consumers. The uncertainty is not in accordance with the charging objectives to "provide stable cost messages".

Islands

In a similar manner to charges for HVDC, the proposed charges for islands have evolved over recent years as we illustrate in Annex 4. For example the additional charges proposed for the link to Orkney halved from ~£40/kW in January 2009 to ~£20/kW in March 2010. This was due to an evolution of the methodology under the same charging principles and objectives.

Even with these reduced charges we show that the charges proposed for Orkney (which is the lowest cost island connection) are about ten times the GB average.

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[3] NGET " The statement of the Use of System Charging Methodology" effective April 1st 2010
[4] ENSG "Our Electricity Transmission Network: A Vision for 2020."

SSE announced in its half-yearly results[5] that it had had not concluded a contract for the HVDC cable and withdrew its request to Ofgem for the investment as there was insufficient user commitment from the generators concerned. The inability to make a commitment has been attributed to the level of transmission charges[6]. The Western Isles link had been identified in the ENSG report as necessary, strategic investment.

Uncertainty for Distributed Generation

There is a degree of confusion and uncertainty with regard to the charges generation connected to distribution networks (embedded) are exposed to. Depending on their size and connection arrangements, generators can be liable for both distribution and transmission charges, which can create a perverse incentive to connect to transmission. In addition a variety of thresholds trigger the Grid Code requirements which influence the capital cost to connect. Many of these thresholds appear arbitrary and have been subject to changes leading to uncertainty which creates risk, pushing up finance costs. For example:

1. Transmission charges may apply to some generators which do not export to the transmission system.
2. National Grid was about to propose applying transmission charges to all embedded generation as low as 30kW. This goes against the trend in England and Wales which has moved transmission charging threshold for these users from 10MW to 50MW and then 100MW. Removal of these and other associated embedded benefits will have a significant detrimental impact to embedded generation.
3. Embedded generation can be subject to high connection cost (through the distribution connection charging regime) as well as user commitment where a statement of works has been requested by the DNO, SO or TO.
4. There is a small generator discount for transmission connected generators at 132kV in Scotland.
5. Offshore generation connected to a DNO at 132kV can pay charges for Offshore Transmission, Onshore Distribution and Onshore Transmission.

[5] SSE financial report for the 6 months to 30 September 2010 (page 18, published 10/11/2010).
[6] Scottish Renewables letter, sent on behalf of generators to DECC on 17/09/2010

Interconnectors and international parity

The European Union has directed that there should be no charges for interconnectors between national networks[7]. As a result Generators exporting from GB have benefitted from the removal on interconnector charges on exports and this is a welcome development.

However the charging regime also removed entry charges from interconnectors[8.] Therefore an interconnector arriving in the north of GB is exempt from entry charges whereas an onshore or offshore generator located or connecting in the same location would pay entry charges, which in some locations could be significant. This can make GB generation less competitive compared to generation from the rest of Europe (including Northern Ireland) arriving through interconnectors.

The charging system for GB generators should be fair and competitive with other countries for both imports and exports.

In Annex 5 we have made some comparisons of charges to illustrate the competitive disadvantage for some GB generators. With increased interconnection to the rest of Europe this will become more and more important in future.

Storage and peaking plant

As the generation mix changes to accommodate the low carbon economy there will be an increasing requirement for peaking and storage plant to ensure security of supply and to respond to market price signals.

Under the current regime, storage is charged identically to other generation on the basis of export capacity, despite the fact that it would be likely to generate when there was spare transmission capacity (e.g. when wind generation was low). Also, despite the fact that a storage plant, located in transmission constrained areas of the network, would reduce constraints when importing energy (to top up its storage), it can be charged for imports as well.

Conventional generation operating as peaking plant (with low annual load factor) which runs when there is surplus transmission capacity has little impact on transmission cost or capacity and yet is

[7] Regulation EU No 714/20093, and equivalent clauses are within the 1228/2003. http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF
[8]See National Grid conclusions document http://www.nationalgrid.com/NR/rdonlyres/52B5CF91-9AE1-467D-9BE1-3620149FA895/42993/GBECM26ConsultationAuthorityReportFinal.pdf

charged identically to other generation. The current transmission charging regime may force premature closure of such plants when they may be important for security of supply.

There is a lack of certainty in the market arrangements (including TNUoS, Capacity Payments and Electricity Market Reform) which are likely to be delaying some investments in new peaking and storage plants. National Grid as system operator is offering 15 year reserve contracts, but it is not possible to realise the certainty this revenue stream can bring, and therefore to cover the network costs, ahead of an investment decision. This is because it is currently only possible for plant which is already built to tender for these contracts i.e. it is not for new plants under development.

SQSS

Some aspects of transmission charging are linked to the SQSS[9]. A fundamental review of the SQSS has been underway for several years and could yet make significant changes in the future. Because of the relationship between charges and the SQSS such changes may have unexpected and unintended consequences for charging creating added risk and uncertainty for investors.

Transmission charging options for TransmiT to consider

At this stage RenewableUK and Scottish Renewables are not advocating any specific options to address the stresses we have identified in the current system. We would like to see many options examined and tested. Some options may solve more problems than others, some options may have perverse outcomes in certain circumstances and some options may be combined in different ways to relieve the stresses we have identified.

RenewableUK and Scottish Renewables have been discussing and debating a number of options which could be examined and we are listing a number here. We realise that we have not provided a full description of these options, or any assessment of the potential pros and cons. We have not examined how they might be combined or which are mutually exclusive. We have not tested them against the desired outcomes or against the current stresses. However we believe it is still useful to list these options in this incomplete form in our response to Ofgem's Call for Evidence. We look forward to exploring some or all in more detail in the near future.

[9] Security and Quality of Supply Standard

The options are in no particular order:

1. Examine the role of the SQSS in charging.
2. Assess options for considering developer's at risk investments in a project as an indication of user commitment from which to progress transmission reinforcements and investments.
3. Continue with capacity charging for generation also considering higher and lower levels of cost reflectivity.
4. Move wholly or partly to energy charging for generation.
5. Options for a common European charging methodology including interconnectors.
6. Only charge for flows at the boundaries of networks particularly flows to/from distribution and private networks.
7. Change the demand generation split from 73%-27% to 100%- 0%.
8. Remove local charging.
9. Review degree of incremental charging to reduce or increase locational signals.
10. Assess postage stamp capacity or energy charging for generation.
11. Review options for fixing charges and/or discounting charges for increased future commitment.
12. Review options for extending generator choice and associated charges.

Principles and Tests

When solutions are considered under Project TransmiT, RenewableUK and Scottish Renewables have the following recommendations about the assessment process.

The assessment process should include a review of charging methodologies used in other markets and countries and the pros and cons of these methodologies in order to learn lessons for the GB market.

The assessment process should examine the proportions and levels of charges currently paid by different technologies in the market and assess likely future payments if the current system is left unchanged and the impact of each proposed change.

We recommend that solutions are assessed against criteria and scenarios to ensure that they are fit for purpose and long lasting and will not prove wanting when there are changes to the connections, generation mix and flows on the network.

There are probably a range of charging methodologies that would meet the charging principles (as we have evidenced in the sections on islands and HVDC above). The principles in themselves do not permit a quantitative comparison of any two different methodologies to determine the optimal choice.

We advocate that a key principal is added which is aligned to European Directives, Government policy and targets, to RIIO and to Ofgem's objectives[10] and is focussed on achieving the renewables targets and decarbonisation of the electricity system.

We note the current Government guidance to Ofgem includes:

> "increase renewable energy levels to 15% of total UK final energy consumption by 2020, as will be required by the proposed Directive on the promotion of the use of energy from renewables sources "

> "reduce greenhouse gas emissions by at least 80% by 2050 from the 1990 baseline, and to establish and implement carbon budgets for the UK to chart the trajectory necessary for achieving this legally binding target as required by the Climate Change Act 2008**;** to reduce carbon emissions by at least 34% from the 1990 baseline by 2020; to meet our share of Europe's 20% reduction in all greenhouse gas emissions by 2020; "

With regard to the relevant European legislation we would highlight Renewables Directive (2009/28/EC Article 16(7)) - implementation by 5 December 2010. Also Renewables Energy under Article 7(6) of the Renewable Electricity Directive (Directive 2001/77) and Electricity Directive (2009/72/EC) - implementation by 3 March 2011

Further information on Ofgem's and GEMA's duties are in Annex 8, our comments on the current charging principles and objectives are in Annex 6 and our recommendations for assessments and testing are in Annex 7.

[10] http://www.decc.gov.uk/assets/decc/consultations/ofgemreview/239-ofgem-review-call-for-evidence.pdf

Transition and phasing

TransmiT must consider how any changes would be phased in so that disruption is minimised and should consider the issues of compensation, windfall charges and grandfathering of existing rights so that existing investments made under the current charging regime are taken into account.

Engagement

We appreciate that this Call for Evidence is the early stage of a process that will continue and develop. RenewableUK and Scottish Renewables want to ensure that we, our members and other market participants have every opportunity to engage with Ofgem and its consultants and advisors in a meaningful manner over the course of TransmiT. This will ensure that the options under consideration have had full industry input and consideration.

Timing and execution of TransmiT

The timing of Project TransmiT is critical. During its course some investment decisions in new generation may be delayed or deferred which could impact on both renewables targets and decarbonisation of electricity. It is imperative that TransmiT is conducted in a timely manner, balancing the need for the review against the uncertainty it creates in the market. Any conclusions or changes should be made with the aim of implementing any new arrangements in an enduring manner without the need for further significant review and change in the next twenty years, or more.

We would welcome a process that will deliver clear and certain decisions on the future nature of transmission charging quickly and effectively with a sensible opportunity for consultation with industry on the options. We are not convinced that the Significant Code Review Process can deliver that certainty and would welcome a more streamlined approach.

Yours sincerely,

Guy Nicholson CEng MIET MEI
Head of Grid
RenewableUK

Niall Stuart
Chief Executive
Scottish Renewables

Annex 1 – Cost Reflectivity

In this Annex we provided some examples where cost reflectivity is not considered appropriate including the example of Beauly-Denny where investment decreases rather than increases charges.

Beauly Denny

Beauly Denny is a significant transmission investment to facilitate the connection of new and future generation.

Under the charging methodology the charges levied on generators north of Beauly will probably[11] fall on its completion, because the voltage has increased from 132kV to 400kV which has a lower cost per MWkm.

In this case it is pertinent to note that investment in the network does not always increase the charges for those benefitting from that investment and that "cost reflective" does not necessarily mean that users who cause extra investment costs will see higher charges as a result of that investment.

Hydro Benefit

The Hydro Benefit is an example of where an exception to cost reflectivity has been seen as a preferred outcome.

Under this scheme the high costs of operating, developing and maintaining the distribution network in the highlands and islands of Scotland is cross subsided by other players and users as it deemed socially unacceptable to charge users the true cost.

Frequency Response

In August 2010, National Grid wrote to Ofgem explaining its decision not to adopt a charging mechanism to target the additional frequency response costs arising from raising the normal and infrequent loss limits in the NETS SQSS to 1320MW and 1800MW respectively.

[11] If no cabling is used it will fall, however, if significant sections of underground cabling are needed to satisfy planning requirements the charges will rise.

National Grid stated that :

> "It is National Grid's view that any potential improvement in cost-reflectivity is outweighed by the negative impact on competition between generators that would be caused by these market inequalities."[12]

[12] GB ECM19 Largest Loss Frequency Response: **Letter to the Authority** Confirmation of National Grid's decision not to progress the proposal 18th August 2010

Annex 2 – Offshore charging

In this Annex we illustrate the interactions between offshore and onshore charging for generation.

Under the current methodology, the development of offshore renewables and the associated transmission results in significant reductions in charges for onshore generators even if the amount of transmission used by onshore generators remains unchanged.

To demonstrate outcome of the current system we have taken the actual 2008/9 annual recovery for GB transmission assets of £1,335M[13] and added on an additional annual offshore transmission (OFTO) cost of £500M. This cost represents offshore assets that would be sufficient to connect 12.5GW of offshore generation at a cost of £400k/MW, i.e. a total asset cost of £5,000M with an annual cost recovery assumed at 10%. The resultant costs attributable to the market participants in both cases can be seen in the chart below.

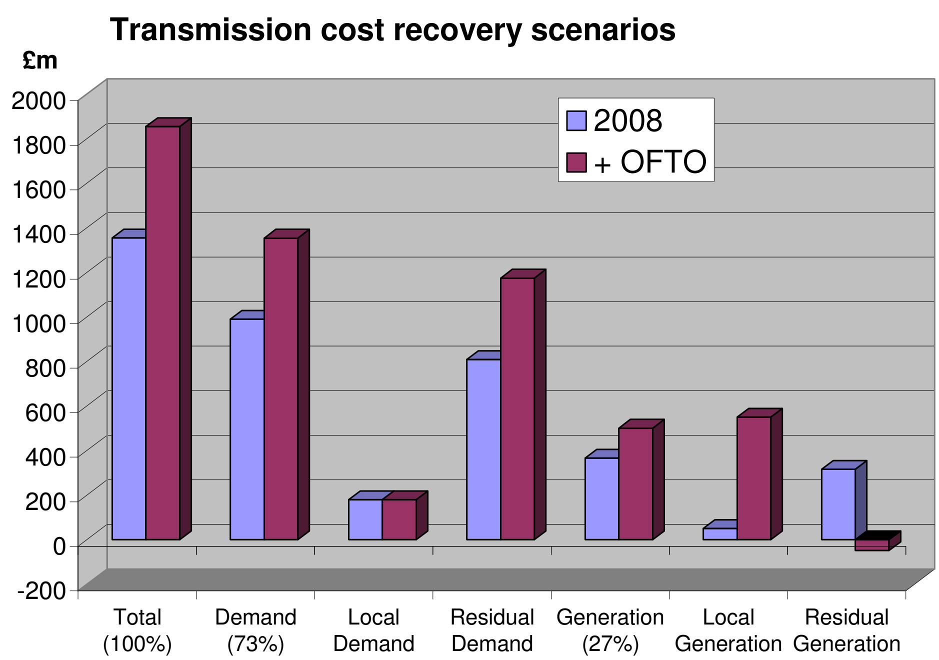

Figure 1: cost recovery of transmission charging in 2008 and after assumed OFTO investment

In both cases (2008 and 2008+OFTO) in the chart, the costs are shared between generation (27%) and demand (73%). However, because the £500m of new offshore assets are classed as "local" assets and charged 100%[14] to the offshore generators connected to them, there is a

[13] NGET "GB-ECM 13 residual charging for generation" TCMF 26 January 2009.
[14] The charge may be nearer to 80% of the costs as some assets may not be classed as "local".

significant increase in “local circuit tariff” income. In the case with the additional £500m of OFTO investment, the “local circuit tariff” income exceeds the total income to be recovered from generation (27% of the total). Therefore the “residual” charge for both onshore and offshore generation reduces and in this scenario onshore generation charges become negative.

Annex 3 – HVDC

In this Annex we show the evolution of charging proposals for HVDC.

HVDC links ("bootstraps") can be an effective solution for reinforcement as they can be delivered with underground and/or subsea cables, which can avoid significant planning impacts and delays. For reinforcements over a long distance HVDC avoids the cost and impacts of new overhead lines, substations and/or substation extensions that would be required for conventional AC solutions.

The current charging methodology has two significant difficulties dealing with HVDC links.

Firstly the charging methodology is based on the costs of 400kV overhead lines, but not the associated substations which are charged via the residual element. The methodology however does not charge HVDC converter stations in the residual element. As a result, compared to the cost of the overhead line element of an AC solution, the cost of the total HVDC solution, including converter stations is 8 to 9 times higher. This means that compared to a conventional onshore reinforcement, the affected users are charged 8-9 times the cost of comparable onshore works[15] even where the total costs of both solutions would be similar.

Secondly the current methodology needs to know the power that will flow on any new asset in order to allocate the charges. However, with HVDC (and unlike AC) the power flow is in the total control of the system operator (SO). The power flow will be set by the SO to optimise the whole system. The charging methodology however must decide a power flow to calculate the charges. The choice of the power flow has a huge impact on the charges as can be seen in Figure 2 below. The charging methodology published for April 2010[16] does not mention HVDC or how HVDC would be accommodated despite the potential for this technology to be deployed as early as 2015[17].

There are two "bootstraps", reinforcements proposed by the ENSG, using offshore HVDC subsea cable links, one on the west coast and one on the east coast. The ENSG has estimated that the HVDC bootstraps are as cost effective as onshore reinforcements[18].

[15] NGET "Charging for HVDC Bootstraps" Sarah Hall, CISG, 6th January 2010
[16] NGET " The statement of the Use of System Charging Methodology" effective April 1st 2010
[17] ENSG "Our Electricity Transmission Network: A Vision for 2020."
[18] Reference needed for cost of bootstraps.

In January 2010 NGET estimated the charges to generators for a single western bootstrap[19] as show in Figure 2 below. Using this data we have estimated how much generators might need to pay to fund the bootstraps.

The ENSG put the capacity of each at 1.8GW and estimate the cost of each interconnector as £700m. This would represent an annual cost of about £70m.

We assumed that charges are higher as the HVDC usage increases and that the effect is approximately linear. The cost increase for generators (read from the chart) is ~£25/kW/annum for a 50% loading, which extrapolates to ~£50/kW/annum increase for a 100% loading. This charge is in addition to the ~£10 to 20/kW/annum charge already applying to zones north of where the Western HVDC would connect. The additional charge would also apply not only to new generation but also to ~8GW of existing generating plant in zones 1-8[20]. If 1.8 GW of new generation were built to utilise the interconnector and the £50/kW/annum increased charge applied to all 9.8GW of affected generation the annual revenue would be (9.8GW*£50/kW) £490m compared to the annual cost of £70m.

The charging methodology in this example charges seven times the actual cost of the new asset. Because the charging regime is revenue neutral to the transmission businesses the £420m annual surplus would be redistributed to all generators including those further south through the residual element of the TNUoS charge.

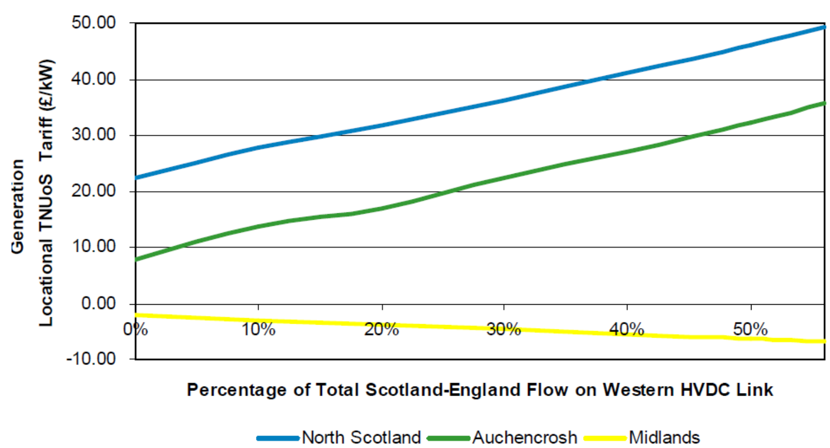

Figure 2: Bootstrap charges estimated by NGET in January 2010[21].

[19] NGET "Charging for HVDC Bootstraps" Sarah Hall, CISG, 6th January 2010.
[20] Auchencrosh (from the chart) is Zone 8 so we have assumed that all generation in Zones 1-8 will see increases in charges.
[21] As footnote above

In February 2010 NGET provided a further and revised view of HVDC bootstrap charging. This data showed that the increase in charges would be much lower and that charges would not increase linearly with utilisation as might have been assumed from Figure 2 above.

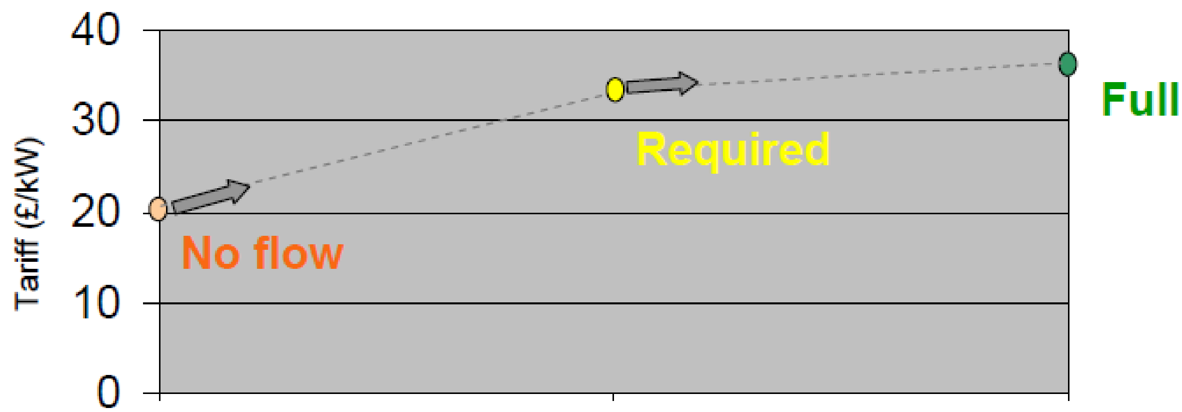

Figure 3: Bootstrap charges estimated by NGET in Feb 2010[22]

Using this information charges would increase by ~£15/kW under the "required" flow condition. Based on 9GW of affected generation this would bring an increase in revenues from affected generators of (9x15) = £135m per annum compared to the annual cost of £70m.

[22]http://www.nationalgrid.com/NR/rdonlyres/4904BFDF-19C4-4C25-9354-70F958406F2A/39941/ENSGbootstrapsLSF084ENSG_final.pdf

Annex 4 - Islands

In this Annex we show how proposed charges for islands have evolved and the relative costs of TNUoS for generators compared to the GB average.

In the March TCMF[23] potential charges for island connections to Orkney, Western Isles and Shetland were presented. For the single circuits proposed these charges would recover the cost of the connection when fully contracted as shown in the table below.

Location			**Orkney**	**Western Isles**	**Shetland**
	Capital Cost	£m	86.00	286.50	547.00
	Annual cost	£m/annum	7.40	24.64	47.04
	Capacity	MW	320	450	600
Charges					
	island differential	£/kW/annum	20.54	54.75	78.40
	Onshore	£/kW/annum	21.59	21.59	21.59
	Total	£/kW/annum	42.13	76.34	99.99
Annual recovery					
	All	£m	13.48	34.35	59.99
	Island only	£m	6.57	24.64	47.04

Table 1: proposed island charging from March TCMF

The island charging proposals have changed over time, for example a generator in Orkney with TEC of 180MW was quoted charges of £61/kW in January 2009[24].

Although the new proposed charges do not over recover the costs of the reinforcement from the users they do still represent a significant cost compared to other generation in other locations.

E.g. for Orkney assuming 320MW of additional wind capacity

- Total UK Generation 75,000 MW (as TEC)
- Orkney Generation 320 MW
- Charges assigned to generation GB £360m
- Orkney generation charges (42.13x 320£k) = £13.5m
- Orkney share of generation charges for GB =3.7%
- Orkney percentage of all GB Generation capacity = 0.43%
- Orkney wind percentage of GB generation output = 0.32%

[23] Transmission Charging Methodology Forum 31 March 2010 National Grid
[24] Fairwind Orkney response to GB ECM 20 http://www.nationalgrid.com/NR/rdonlyres/FA35D016-C4D2-401B-885E-84357A4F946C/39629/GBECM20FullResponses.pdf

The Orkney zone would be paying approximately 9 times more than the average based on generation capacity and 11 times more based on energy generated.

In addition there is a major concern with regard to the risk to the generator of a circuit failure for these island connections given that there is no network redundancy either full or partial[25].

[25] Partial redundancy can be achieved by providing wind generation capacity through two circuits. Under and n-1 condition only 50% of the capacity is available but >50% of the energy (maybe ~70%) can still be secured due to the variability of wind generation.

Annex 5 - Europe

In this Annex we have made some comparisons of charges to illustrate the competitive disadvantage for some GB generators.

The transmission charge in Northern Ireland (NI) is allowed to be locational. However for the third year running, the decision has been taken to postpone the locational element of the charges and remain in a postage stamp charging regime.

The NI charge for 1st Oct 2010 - 30th Sept 2011 is £3.00/kW of contracted capacity.

Charging statement:
http://www.soni.ltd.uk/upload/TUoS%20CHARGING%20STATEMENT%202010-11%20v1.1.pdf

The transmission charge in the Republic of Ireland (RoI) has now become locational. The charges are split into three categories: Transmission (T) connected wind farms; Distribution (D) connected wind farms; and other plant. Charges range from €0 to €10.30/kW, although the ranges are generally narrower within the three categories. There are no negative charges and the range is much flatter than the GB charges.

Charging statement:
http://www.eirgrid.com/media/2010-2011%20Statement%20of%20Charges%20-%20Approved%20by%20CER%20-%20Published%2030%2009%2010.pdf

The export charges on the Moyle are based on auction prices. The average for 2009 appears to be £0.43/kW PER MONTH but it doesn't look like all months have export capacity.

http://www.nienergyholdings.com/Download/AuctionPricesandallocations060401on.xls

In conclusion, a generator in the RoI would therefore pay (per annum) between £5/kW and £15/kW and in Northern Ireland £8/kW to serve a customer in the North of Scotland whereas a local generator would have to pay £22/kW (ignoring the customer's demand charges which would be the same for both cases).

Annex 6 - Current Principles and Objectives

We have reviewed the current principles[26] (items 1-3) and further objectives[27] (items 4-11) which, when broken down into their component parts, total eleven items and which we summarise with the following key words:

1. Facilitate Competition
2. Cost reflective
3. Business Reflective
4. Clarity
5. Transparency
6. Accurate
7. Stable
8. Services provided basis
9. Incremental cost
10. Promote optimal use and investment
11. Implementable.

In our review for each item we have considered:

- What does the principle/ objective mean?
- Is it a good principle?
- Is it met in the current regime?

We have decided not to include our review of the current principles and objectives because there are some differing views on a few of the assessments.

We are agreed that a number of different methodologies (with very different results for different market participants) could be considered to satisfy these principles and objectives. The inability to agree stems largely from the fact that the objectives are not clearly stated and cannot be readily measured.

As the principles and objectives and are not weighted or prioritised we have not been able to assess the current charging methodology. We therefore question the value of the current principles and objectives.

[26] National Grid's Licence Condition C5
[27] National Grid's statement of the Use of System Charging Methodology - Paragraph 1.9

The full list of principles and objectives is replicated below.

The GB Transmission Use of System Charging Methodology has the following objectives as set out in National Grids Licence Condition C5 which requires the charges to:

a "Facilitate Competition - 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;

b Cost Reflective - that compliance with the Use of System Charging Methodology results in charges which reflect, as far as 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 businesses; and

c Business Reflective - that the Use of System charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

In setting and reviewing these charges National Grid has a number of further objectives. These are to:

i. offer clarity of principles and transparency of the methodology;
ii. inform existing Users and potential new entrants with accurate and stable cost messages;
iii. charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
iv. be implementable within practical cost parameters and time-scales"

Annex 7 - Assessment and Tests

In this Annex we propose a set of tests which should be applied to all proposed changes to the charging regime to ensure that it meets the principles achieves the objectives and is immune to future changes and developments in the market and technologies.

When solutions are considered under Project TransmiT, RenewableUK and Scottish Renewables have the following recommendations about the assessment process.

The assessment process should include a review of charging methodologies used in other markets and countries and the pros and cons of these methodologies in order to learn lessons for the GB market.

The assessment process should examine the proportions and levels of charges currently paid by different technologies in the market and assess likely future payments if the current system is left unchanged and the impact of each proposed change.

We recommend that solutions are assessed against criteria and scenarios to ensure that they are fit for purpose and long lasting and will not prove wanting when there are changes to the connections, generation mix and flows on the network.

In our view the assessment should consider if the solutions:

- Meet the stated principles.
- Facilitate the low carbon economy including the enhanced role of demand side management, smart grids.
- Support progress towards meeting the 2020 renewable energy targets and decarbonisation of electricity by 2030.
- Facilitate the future substitution of fossil fuels for electricity in the heat and transport sectors.
- Facilitate competition between generators of different technologies and between generators in different locations including those locating in GB and those located in Europe.
- Are mutually exclusive and which can be considered together?

- Address some or all of the problems identified, or if some solutions exacerbate some of the current problems.
- Impact on different technologies equally or do some technologies bear the brunt of the charges as a result.
- Provide the certainty which will support the lower cost financing for the capital intensive generation required for a low carbon future.
- Are future proof to changes in the area of application (e.g. to GB and beyond)
- Are future proof to changes in demand including changes to peak demand driven by variable renewables and DSM?
- Are future proof to changes in generation technology, their characteristics, locations including offshore wind, wave and tidal, solar PV and combinations given potential technology and cost developments over the next forty years?
- Are and will be compatible with European regulations and directives (see Annex 9 below)

To test the different solutions brought forward a number of scenarios and hypothetical test systems should be developed which include the current GB system but different systems including different networks, geographies and a generation mixes. This should include new offshore generation and interconnectors connecting to HVDC bootstraps, to existing OFTO assets and to DNO networks.

Annex 8 - Ofgem's and GEMA's Duties

Ofgem's duties are currently under review by DECC[28]:

The current government guidance to Ofgem includes:

> "increase renewable energy levels to 15% of total UK final energy consumption by 2020, as will be required by the proposed Directive on the promotion of the use of energy from renewables sources "
>
> "reduce greenhouse gas emissions by at least 80% by 2050 from the 1990 baseline, and to establish and implement carbon budgets for the UK to chart the trajectory necessary for achieving this legally binding target as required by the Climate Change Act 2008; to reduce carbon emissions by at least 34% from the 1990 baseline by 2020; to meet our share of Europe's 20% reduction in all greenhouse gas emissions by 2020; "

The duties of GEMA under the 2010 Energy Act includes:

> "General duties of the Gas and Electricity Markets Authority and the Secretary of State
>
> 76. In carrying out its duties, Ofgem must act according to its objectives as set out in statute. Ofgem has a principal objective to protect the interests of existing and future consumers. Wherever it is appropriate to do so, it must fulfil that principal objective by promoting effective competition. The interests of consumers are not currently defined. Ofgem must also take into account a range of secondary objectives.
>
> 77. It is the Government's view that reducing greenhouse gas emissions (in order to mitigate climate change) and ensuring secure energy supplies are both in the interests of future and existing consumers and should be considered as such by Ofgem when carrying out its functions. The Government does not intend to change Ofgem's principal objective nor to create multiple principal duties through these provisions, but to ensure that in its interpretation of its existing principal objective of protecting consumers, Ofgem gives due weight to the need to reduce greenhouse gas emissions and ensure security of supply.
>
> 78. Competitive solutions may take time to deliver, and the market may create barriers for some groups of consumers so that the promotion of competition may not be the most effective means of protecting their interests. These provisions clarify that Ofgem should

[28] http://www.decc.gov.uk/assets/decc/consultations/ofgemreview/239-ofgem-review-call-for-evidence.pdf

consider using alternative types of solution to address the consumer detriment instead of, or alongside, measures to promote competition. Such solutions could include strengthened licence conditions and enforcement action, or other means that would prevent certain types of market behaviours."

Annex 9 – Relevant European Directives

The following directives should be considered in TransmiT.

Renewables Directive (2009/28/EC Article 16(7)) - implementation by 5 December 2010
Also Renewables Energy under Article 7(6) of the Renewable Electricity Directive (Directive 2001/77).

> "Those [charging] rules shall be based on **objective, transparent and non discriminatory criteria taking particular account of all the costs and benefits associated with the connection of those producers to the grid and of the particular circumstances of producers located in peripheral regions and in regions of low population density"**

> "Member States shall ensure that the **charging of transmission and distribution tariffs does not discriminate against electricity from renewable energy sources, including in particular electricity from renewable energy sources produced in peripheral regions, such as island regions, and in regions of low population density"**

Electricity Directive (2009/72/EC) - implementation by 3 March 2011

> "National regulatory authorities should be able to fix or approve tariffs, or the methodologies underlying the calculation of tariffs.[and] should ensure that **transmission and distribution tariffs are non-discriminatory and cost-reflective"**

COMMISSION REGULATION (EU) No 774/2010 of 2 September 2010

> "Annual average transmission charges paid by producers in Ireland, Great Britain and Northern Ireland shall be within a range of 0 to 2,5 EUR/MWh, and in Romania within a range of 0 to 2,0 EUR/MWh".