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1. Executive Summary

The Project TransmiT review is a welcome initiative by Ofgem. In order to facilitate the timely move to a low carbon energy sector, the focus of the review should be on electricity transmission and in particular the charging arrangements. We believe that there is strong evidence to suggest that the Government's and Ofgem's objectives in relation to climate change and indeed renewables, are in danger of not being achieved as a result of the current charging methodology. Our response therefore focuses on the electricity transmission charging arrangements.

This review can be seen as a one-off chance to deliver against renewable and security of supply targets. As such, the review needs to come to a speedy conclusion. This suggests that the solution needs to be one that is simple and be guaranteed to bring forward increased renewable deployment. It would be unacceptable to gamble on the chance of implementing another complex methodology (e.g. another version of incremental cost related pricing (ICRP) or one that includes time of use charges) that will take time to develop and implement, but, be no more certain than the existing ICRP methodology in bringing forward renewables. We have put forward a simple framework that we believe can achieve this.

It is clear from the work by carried out by Ofgem on Project Discovery, that a Green Transition or Green Stimulus package will best meet security of supply and renewable ambitions at least cost to customers. However, the current arrangements for charging for access to the GB transmission network do not encourage investment in new renewable generating capacity. The incremental cost related pricing model used by National Grid in setting Transmission Network Use of System (TNUoS) tariffs is complex, and results in TNUoS tariffs that are extreme, volatile and unpredictable and not cost-reflective. Further they are distorting retail competition, are having an adverse impact on security of supply and are at odds with the creation of a wider European market.

The existing methodology focuses on an attempt at cost-reflective pricing, yet it can be shown to fail to achieve this. It should also be recognised that cost-reflectivity is itself only an objective to be met where it is "reasonably practicable". This blind adherence to cost-reflectivity needs to be abandoned. Cost-reflectivity needs to be recognised as a means to an end, rather than an aim. The end should be efficient investment in infrastructure to allow the Government to meet its legally binding climate change targets. The methodology for charging for use of system needs to be considered in the wider context of meeting renewable and climate change goals.

The current ICRP methodology was designed shortly after privatisation for a large-scale, concentrated, thermal generation plant mix that existed solely in E&W and separate to the Scottish market and the two Scottish transmission systems. With the increase in generation competition, and the roll-out of the methodology to cover the Scottish transmission networks at BETTA in 2005, problems with the methodology began to arise e.g. around the inclusion of the Scottish 132kV network as transmission. As renewable development has increased, the problems with the methodology have also increased.

These problems have been most recently illustrated on Orkney and the Western Isles. On Orkney, the Fairwind project has been cancelled due to the high transmission charges. On the Western Isles, due to the lack of financial underwriting from electricity generators (attributed to the level of transmission charges) relating to the link from the Western Isles to the mainland, the investment in the cable is not going ahead.

The flaws in the methodology have also been seen through the predicted charges for the construction of the HVDC links, the "bootstraps", more than doubling charges in the North of Scotland. It creates a Catch 22. The bootstraps are needed to allow new renewable generation to connect and generate. However, with charges at £50/kW this would make the economics prohibitive and so no new renewables would get built. The ICRP model would also add the costs of the bootstraps to the already prohibitive charges for the Scottish islands. If National Grid believe that their charging model is robust, that the charges it produces are cost reflective and are providing the correct signal for where new generation should connect, then they should not be going ahead with their investment in the "bootstraps".

A further deficiency has been highlighted by the recent decision by Ofgem to remove charges from the Interconnectors. This is likely to result in perverse outcomes e.g. a Norwegian interconnector could connect and bring energy into the North of Scotland, pay no use of system charges but cause a dramatic increase in charges to all other generation in the North. Should this review (of transmission charging) conclude that Interconnectors can continue to be treated differently from all other Users with respect to the methodology for transmission charging in GB, we believe that this decision would be discriminatory and challengeable.

At implementation, the original ICRP model for E&W considered the sensitivity of the model for various generation and demand scenarios. The most extreme result under the scenarios was an increase of £3.30/kW. The conclusion drawn was that the model was robust to the input assumptions and scenarios tested. Given the level of changes being seen now from the model, it is clear that the existing model fails to meet those original standards on an ongoing year-to-year basis and more so when large-scale additions to the network to accommodate new renewables are considered, e.g. the bootstraps. If brought forward for implementation today, the ICRP model would be rejected.

These recent examples of perverse and extreme charges from the model, and the recent instances of projects being cancelled bring home the truth that without a change to the methodology, the Government will not meet its legally binding targets. It would be a failure of the review if the same deficiencies remained and set charges at similar levels for the Scottish Islands and the bootstraps in any new methodology.

We believe that the renewable and climate change goals can be achieved through the implementation of a simple framework consisting of:

- a uniform commodity charge for the use of wider shared transmission assets along with a locational signal provided through a combination of
    - i) a local connection charge and
    - ii) potentially a locational transmission loss factor
- a fairer and more proportionate User Commitment

Whilst our views on the failings of the current charging methodology apply equally to demand-side tariffs; the impact on competition in supply is less acute given that all suppliers face the same transmission charge for any individual customer and the main driver for change to the methodology is moving to a low carbon generation sector. So whilst in principle we have no objection to the framework proposed here being applied to both generation and demand across GB, it is put forward and described here in its application to generator charges only.

The proposed framework will have the benefits of being:

- Simple;
- Quick to implement;
- Support Government objectives;
- Predictable;
- Non-discriminatory;
- More cost reflective; and
- Be a positive step towards a wider European market.

This framework, based on a uniform commodity charge is in our view, more cost-reflective than the existing ICRP methodology. The framework set out here, rather than falling into the trap of inefficient and inaccurate allocation of costs, seeks instead to allocate these costs on an average basis.

The use of a uniform commodity charge is proposed here as there is strong evidence that the current locationally varying element of the tariff is no more cost-reflective than a uniform tariff approach. In considering the specific issue of the cost-reflectivity of the current TNUoS tariff, the correlation between TNUoS (specifically, the locational element) and transmission investment was examined in detail as part of the Transmission Access Review. The conclusion reached was that TNUoS is <u>not</u> a good proxy for network investment.

In addition, where charges cannot be shown to be doing what they are meant to, and are going against the public good by adversely impacting on new renewable generation and security of supply, a move to a uniform commodity charge that will allow the Government to better meet its renewable and climate change targets can be considered a public policy benefit.

Consequently, we believe that replacing a charge that is not cost-reflective with an average charge is a relative improvement, and the case is compelling when the many other benefits of a uniform tariff are also taken into account. An allocation of costs through a uniform commodity charge that is <u>right on average</u> is preferable to an allocation that that purports to be cost-reflective yet is <u>demonstrably wrong for everyone</u>.

The use of a uniform commodity charge can also rely on a number of precedents within the electricity market arrangements justified as achieving climate change and renewable objectives, or bringing an economic or societal benefit, e.g. BSUoS charging and frequency response costs. It can also be shown to be consistent with the majority of schemes across Europe.

Importantly, this framework moves away from the blind adherence to cost-reflectivity. Rather, it meets the wider need of renewable and climate change goals.

The second most significant issue facing new generation project developments, that is linked to transmission charging, is the level of liabilities that developers face to connect to the transmission system. This presents a significant barrier to new developers and reform needs to be a high priority of the review. The framework we propose here puts forward reform of the FSL and changes to the User Commitment requirements to address this issue.

Whilst not within the scope of this review, the proposals for zonal (locational) transmission losses under the BSC would only add to the punitive nature of transmission charges. Such a doubling of the locational penalty would be both discriminatory and disproportionate. We believe that the implementation of any new transmission losses scheme needs to be considered as part of this review and that the decision on BSC Modification P229 should not be made until the review has concluded. This view aligns with Ofgem's view of 1999[8], that it may be inefficient to expose participants to both sets of locational charges. We will continue to resist the imposition of a zonal losses scheme in combination with the existing ICRP methodology. However, the framework proposed here could sit comfortably with a zonal transmission losses scheme.

The original ICRP methodology was phased in over three years recognising that users may find it difficult to adjust to a change in their cost for use of system overnight. Any fundamental shift in the methodology will similarly need to consider the implementation timetable.

2. Scope

The focus of the review should be on the electricity transmission charging arrangements, including the level and form of User Commitment requirements. In principle, the review should consider charging arrangements for both generation and demand. However, the priority should be on resolving the issues on the generation side as meeting renewable and climate change targets are a more urgent objective. The current level and form of User Commitment, is also having an adverse effect on investment and this area should therefore be the second most significant issue, behind charging, for the review. The focus of the review should remain narrow, as there is a risk that the wider the scope the longer it will take to come to any conclusions.

In line with this view, we do not believe that there is a need at this point in time to make radical changes to the charging arrangements for gas transmission. Nor indeed is there a need to consider making the models for access and charging the same across electricity and gas. The dynamics of operation are sufficiently different, and there is not the urgency for change in gas as there is to move electricity to a low carbon base. Gas transmission should not be part of the review. Any problems of consistency can be addressed at a later date. In addition, the use of and charging for existing gas network assets for CCS transportation should not be part of the scope of the review.

The review of electricity transmission charging should include the whole of the transmission system in mainland GB, transmission in offshore waters, island connections, and interconnection with external markets. As part of this, the review should consider the interfaces at boundaries between e.g. the transmission and the offshore networks, interconnectors and the distribution networks. There needs to be a consistency/sense check of any new methodology at these interfaces. It would also be relevant to consider the boundary between Use of System charges and Connections charges. This would include the level of security provided and charged for new (customer choice) connections.

The current ICRP methodology is at odds with requirements from Europe. Any new methodology must comply with and be compatible with European regulations.

The review must include the consideration of Transmission Losses charging. Whilst this is currently before the Authority for decision, through the BSC processes (Modification P229), any attempt at providing a locational signal needs to take account of the impact of both the Use of System charge and the transmission losses charge. The outcome of the review would be prejudiced if a decision was taken by the Authority on P229 whilst the review was ongoing. In light of this, we believe that a decision on P229 should not be taken until the review has come to a policy conclusion on locational signals for transmission charging and losses.

A fundamental review of the SQSS has been underway for some time. It, like the TPCR, should not be allowed to deflect or delay what should be the main focus of the review, electricity transmission charging.

Finally, following DECC's Transmission Access Review and subsequent legislation, transmission access and locational BSUoS should both be outwith the review.

3. Background to the Existing Electricity Transmission Charging Arrangements

The current ICRP charging methodology and associated model was developed in 1992 and introduced in 1993/94. The intention of the charging methodology was to reflect the Transmission Owners' (TOs') costs for installing and maintaining the transmission system based on the impact of future users in different locations across the system. The model was intended to provide economic signals to both users and TOs to indicate the optimum level and location of investment. The model was introduced into England and Wales only. The E&W transmission system can be described as a highly meshed 275/400kV system. The generation profile at that time was one of large pre-privatisation thermal (fossil and nuclear) generation in the hands of a small number of players (the only large scale new generator that had been built between privatisation and the introduction of ICRP was Teessside power station, an independent owner). The charges were phased in over three years to allow users to adjust to the change in costs.

In 2005, as part of BETTA, the ICRP transmission charging model was rolled out to cover Scotland. The Scottish transmission system differs significantly from that in E&W. It operates at 132/275kV rather than 275/400kV and is not as highly meshed, more radial, bringing a large number of relatively small scale renewable (mainly hydro) generators to the market. The vast majority of these generators are connected to the main system by single circuits rather than having the security of two circuits as would be the general case in E&W. The main Scottish system is connected to the main E&W system through the "Interconnector" circuits. These circuits were built and upgraded over time to a lower security standard than those in the Transmission Licensees areas.

With increasing renewables targets and climate change goals and security of supply concerns, the transmission system is dominated by increasing onshore and offshore wind in, what are, non-central, or peripheral areas and the closure of fossil fuel power stations. There is growing evidence that the transmission charging regime is no longer fit for purpose, is having adverse consequences for investment and as such is not sustainable. Indeed, tested against the criteria used when the original ICRP methodology was introduced, the current model and its current failings would no longer be approved for implementation. We provide a critique of the current methodology in the next section.

4. Failings of the current ICRP Methodology

There is growing evidence of the weaknesses and failings of the current ICRP methodology. The most compelling deficiencies in the model have been highlighted very recently. These are:

4.1 Western Isles

National Grid's estimated transmission charges presented in March 2010 indicated a total charge of some £76/kW for generation connecting to the transmission system on the Western Isles. As part of their presentation the distance (equivalent miles used in the model of some 5031km) between Scotland and the Western Isles would suggest that the islands are closer to the East coast of America than they are to Scotland. It is little wonder then that it was recently announced that due to the lack of financial underwriting from electricity generators, including a consented windfarm (and attributed to the level of transmission charges) relating to the link from the Western Isles to the mainland, the investment in the cable is not going ahead. The charges being thrown out by National Grid's ICRP model have effectively stopped development of generation on the Western Isles. In addition, given the estimated transmission charge for generation on Orkney is £42/kW and the Shetland Islands is almost £100/kW, it is also likely to prevent development on these islands. These areas could provide around 1,000MW of new renewable generation (projects consented or under development), at high load factors. Development in these locations is unlikely to go ahead under the current ICRP methodology, to the detriment of achieving the Government's renewables targets.

4.2 The Bootstraps

National Grid have also published forward looking estimates of the transmission charges that would be levelled at generators in Scotland following the installation of the HVDC links, or "bootstraps" down the East and West coasts from Scotland to Teesside/Deeside respectively. In this case, the level of charges that comes out of National Grid's ICRP model would more than double the transmission charges in the North of Scotland. Not only would this impact on new generation, it also hits existing generation. For example, even if it is assumed that the existing model was correct and an annual charge for Peterhead of £22m per year was justified, there can be no justification for its charge to more than double to £55m per year when its operation had not changed (note that this would be some three quarters of the annual cost of the whole of the North of Scotland transmission asset base of £74m/year). We have already reduced generation and TEC at Peterhead at the current level of charges. A transmission charge at this predicted level is likely to close the station.

It is also likely to stop development of new renewables in the North of Scotland. Of course, if no renewables were to get built then there would be no need for the bootstraps. It creates a Catch 22. The bootstraps are needed to allow new renewable generation to connect and generate in Scotland. However, with transmission charges of some £50/kW this would make the economics prohibitive and so no new renewables would get built. The ICRP model would also add the costs of the bootstraps to the already prohibitive charges for the islands. If National Grid believe in their charging model, that the charges it produces are cost reflective and are providing the correct signal for where new generation should connect, then National Grid should not be going ahead with their investment in the bootstraps.

4.3 Interconnector Charges

Ofgem's recent decision to allow Interconnector transmission charges to be removed has highlighted that the GB model does not sit comfortably with the creation of regional markets envisaged by the changes emerging from Europe. It creates perverse incentives for Interconnection that would result in significant detriment to GB generation. Take for example, an Interconnector connecting in the North of Scotland bringing energy from Norway. Following Ofgem's decision, the Interconnector flows would be charged nothing for using the GB transmission system, yet would cause the transmission charges to all generation in Scotland to increase. This increase is likely to be significant. Such a potential outcome is likely to undermine investment in all generation, existing and new, in Scotland. The removal of the Interconnector charges would also make it easier for generation in continental Europe (who pay no GB transmission charges) to supply demand in Scotland than it would be for e.g. Peterhead to do so. In addition, any shortfall in funding (as the Interconnetor would make no contribution to use of system costs) would have to be paid for by all other participants. This is a distortion of trade and further discriminates against Scottish generation. Whilst barriers to cross border trade should be minimised the removal of transmission charges from Interconnectors alone (and not all generation and demand) is discriminatory and further distorts trade within the EU.

Should this review (of transmission charging) conclude that Interconnectors can continue to be treated differently from all other Users with respect to the methodology for transmission charging in GB, we believe that this decision would be discriminatory and challengeable.

4.4 Cost reflectivity

In simple terms, the transmission tariff is based on an implausible worst case scenario where all generation and demand is operating at maximum capacity at all times. In reality, this is never the case and this assumption understates the spare capacity available. Therefore, in effect, the transmission tariff is not cost reflective in that it recovers based on 100% use of the system even if the user is not generating and implies reinforcement that is not actually necessary. If this approach was adopted for investment planning, it would result in highly inefficient 'gold plating' of the network.

This is also the case in zones where the generator is paid to access the transmission system. In this scenario, the generator will be paid whether or not there is any actual generation output. Both of these simple circumstances illustrate that the tariffs cannot be cost reflective based on the user's actual use of the transmission system.

Cost reflectivity would also mean a user being held responsible for the change in costs their operation brings about. Yet the existing methodology results in changes in costs being imposed on a user even when their operation has not changed. In this way it cannot be considered cost reflective.

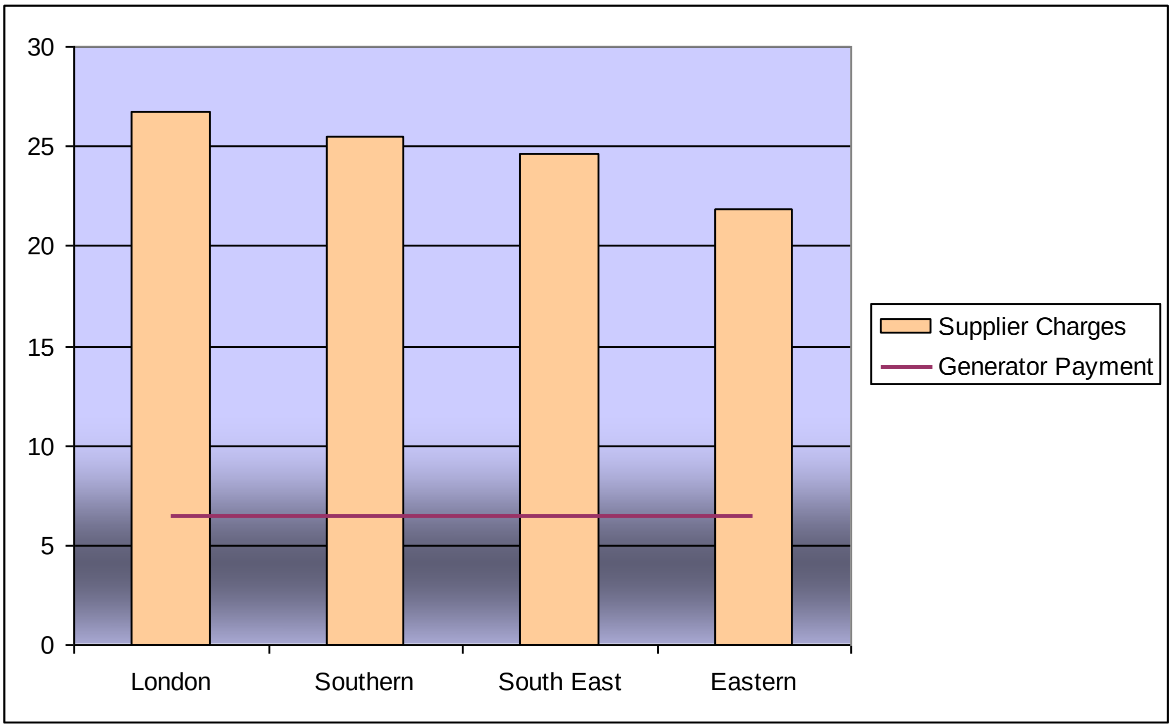
The transmission tariff consists of two elements, the residual charge and the locational charge. The residual charge exists to ensure adequate revenue recovery once the locational charge has been calculated. The locational charge is intended to ensure that future users can assess the cost of their connection depending on their locational impact on the transmission system. In order to calculate what those contributions should be, the locational charge is constructed as follows –

Marginal Investment Cost (MWkm) x Expansion Constant x Security Factor

4.4.1 Marginal Investment Cost

The Marginal Investment Cost reflects the necessary investment required to facilitate an increase in generation or demand at a certain location. This calculation is carried out in National Grid's proprietary DCLF ICRP Transport Model which produces a Marginal Investment Cost for each transmission node across GB. To simplify the charges to users, nodes which have similar costs (i.e. within £1/kW of each other) and are in relatively close proximity are aggregated into a zone and then a zonal charge is applied. Given that the Marginal Investment Costs for generation and demand at each node are inversely proportional, it would be expected that the boundaries of the generation and demand zones would be the same. However, whilst the aggregation of generation nodes into 20 generation zones strictly applies the +/- £1/kW criteria, the demand nodes are simply allocated to the existing 14 distribution zones. In addition, the demand charges are floored at a positive charge whilst negative charges are allowed to flow through to generation charges. This arbitrary floor creates distortion and inconsistency in the charging regime. These suggest that neither the demand zone nor the generation zone tariffs are cost reflective (as the wider demand zone will include nodes which have a greater variance than £1/kW from each other), that the zone boundaries and floor on demand charges are arbitrary and cause distortion.

An example of where the zones fail to provide cost reflective tariffs is in Central London. The generation zone transmission tariff for Central London (zone 16) is such that generators are paid £6.41/kW. This is the highest rate paid to generators across GB, which reflects the desirability (according to the ICRP model) for generators to locate there. Equally, demand zone transmission tariffs may be expected to be at their highest level in Central London. However, because the demand and generation zone boundaries are different, some demand which is located in Central London generation zone falls into the demand zones Eastern, Southern and South East, as well as the Central London demand zone. Therefore, demand located in this Central London generation zone could end up paying the highest demand tariff (£26.76/kW London zone) or one which is some 20% lower (£21.84/kW Eastern zone). If the tariffs are in fact cost reflective, it would be expected that all customers located in this high demand region would contribute equally to the system costs in that area – this, however, is clearly not the case.



4.4.2 Expansion Constant

Once calculated, the Marginal Investment Cost is then multiplied by the Expansion Constant which reflects the <u>existing</u> type and voltage of the transmission infrastructure. However, this calculation ignores any potential for low cost or alternative methods of adding capacity, some of which National Grid themselves have used extensively. For example, re-conductoring, bundling and up-rating voltage all increase capacity on the network for a fraction of the cost of a new line. Given wider environmental and cost considerations, new build is frequently seen as a last, rather than first, resort.

Furthermore, the use of existing assets in the Expansion Constant significantly skews the assumed cost of transmission infrastructure in Scotland. In England and Wales, 132kV lines and cables are treated as distribution, however in Scotland, this voltage is treated as part of the transmission network. As the expansion factor for 132kV line is 2.24, the model assumes that the costs are 2.24 times higher than that of 400kV line. However, it is unlikely that a prudent operator would expand the network using 132kV line when 275kV or 400kV is less expensive.

The NERA[1] study in 2004 found that National Grid had increased capacity on the network by approximately 17% between 1992 and 2004 but had only added 3% more circuit length. These figures in themselves prove that the tariff does not reflect the actual cost of expanding the network. Whilst National Grid use an expansion constant of around £10/MWkm, NERA estimate the actual cost of how the network is being upgraded to be around 55% of this figure, suggesting that the cost assumptions used by National Grid are both inflated and subjective. This is particularly evident when considering ScottishPower Transmission (SPT) upgrade of the Cheviot interconnector which has been achieved through series compensation rather than a rebuild of the line. The expansion constant approach would have SPT build a brand new 400kV line rather than take a more cost effective uprating route.

Additionally, the expansion constant is based on the existing infrastructure rather than providing a forward-looking view of the most efficient type of infrastructure. Not only is this out of step with the intention of the LRIC model and inconsistent with the other two parts of the initial tariff calculation, applying a historic cost to a forward looking signal again challenges the apparent 'cost reflectivity' of the tariff.

4.4.3 Security Factor

The Security Factor is used to capture the costs of security of supply requirements as stipulated in the Security and Quality of Supply Standard (SQSS). Once the Marginal Investment Cost has been calculated and multiplied by the Expansion Constant and the Expansion Factor to take into account the type of infrastructure in place, the result is virtually doubled by applying the Security Factor (which is currently 1.8). The simple rationale behind this is that National Grid consider the cost of providing two circuits to be effectively twice that of providing one.

This does not make any allowance for generators who are already connected to the transmission system with no redundancy as they are still required to pay tariffs which include the Security Factor. Furthermore, there is no incentive on generators to work with the TO to find the most economic and efficient method of connection (which in some cases may be a connection standard below SQSS requirements) as they will be charged regardless of their actual connection infrastructure. This is inconsistent with how the Expansion Constant is applied – where the Expansion Constant depends on what voltage of line or cable is currently in place, the Security Factor is applied no matter what type of connection infrastructure is currently in place.

The Security Factor is intended to provide security of supply to customers by ensuring that generation has sufficient redundancy to enable access to the system in the event of a circuit fault. Although the charge is only applied to generators, it is actually in place to ensure supply to customers. The demand tariffs do not carry this charge for supply security, even though it is for their benefit.

4.4.4 Overall Cost Reflectivity

Whilst the calculations above appear to be unable to provide appropriate cost reflectivity, there is further, specific evidence that the results of the model can be inaccurate.

Recent reviews of proposed transmission connections in the North of Scotland have highlighted that National Grid's ICRP Transport Model is feeding into tariff recommendations which are far in excess of the actual investment, financing and operating costs of the connection.

In Orkney, where Fairwind Orkney Ltd proposed a 126MW wind development, National Grid's model produced a tariff which is over 50% higher than actual cost[2]. This proposed development has now been cancelled due to the high cost of transmission charges.[3]

In Shetland, the tariff indicated to Viking Energy for their proposed 300MW wind development was in the region of three times greater than the actual investment and operating costs of the subsea link required to transmit the energy to mainland GB[4].

Most recently, on the Western Isles, due to the lack of financial underwriting from electricity generators (attributed to the level of transmission charges) relating to the link from the Western Isles to the mainland, the investment in the cable is not going ahead.

The additional infrastructure investment for the Beauly Denny upgrade is to facilitate the connection of new renewable generation. However, the current charging methodology produces charges to generators North of Beauly that will reduce when the upgrade is complete. This appears to be as a result of the lines being increased to 400kV from 132kV. The fact that those causing the investment to take place find their costs lowering cannot be considered cost reflective. It also provides a perverse signal to create a situation where such an effect is reproduced (i.e. a step change in the voltage of the circuits) by building bigger generation projects than would otherwise have been the case.

In relation to the infrastructure associated with the "bootstraps", the ENSG put the cost of each interconnector as £700m, for a capacity 1.8GW each. This would represent an annual cost of about £70m. The transmission charge projected by National Grid is some £50/kW. The additional charge would apply not only to new generation but also to some 8GW of existing generating plant in Scotland. If 1.8 GW of new generation were built to utilise the interconnector and the £50/kW/annum charge applied to all 9.8GW of affected generation the annual revenue would be some £490m compared to the annual cost of £70m. The charging methodology in this case charges seven times the actual cost of the new asset. In addition, 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.

Another example is how generation in Southern England are paid to 'use' the transmission system. It is demonstrably the case that it costs money to build and operate the transmission system for those users – the transmission network built in Southern England is not 'free'. However, as these generators do not pay (but rather are paid) anything for their use of the transmission system this further undermines the 'cost reflective' basis of the current methodology. In addition this 'shortfall' (by virtue of the southern generators not paying) has to be paid for by other generators out with the negative charging areas. Thus generators in the positive areas pay, according to the ICRP model, (i) the cost associated with their actual use of the transmission system plus (ii) the cost of the Southern generators using the transmission system and (iii) the payments made to the Southern generators as well – triple jeopardy. Not only is this not cost reflective it is also discriminatory and distorts trade.

Cost reflectivity should mean (i) a user being held responsible for the change in costs their operation brings about and (ii) to complement this, where a user makes no change in their operation, there should be no change in their costs. The existing methodology fails on both counts. The example of an Interconnector landing in the North of Scotland highlights both. The Interconnector would not be charged for energy coming into GB even if reinforcement of the network was required. It would also cause a significant increase in charges to other Users, both existing and prospective. In this way, the existing methodology cannot be considered cost reflective.

Rather than being driven by the narrow focus of seeking (but demonstrably failing to achieve) cost-reflectivity, the methodology for charging for use of system needs to be considered in the wider context of meeting renewable and climate change goals.

4.4.5 Summary

The current transmission tariffs are not cost reflective because –

- They are based on 100% system usage which never occurs and therefore understate system capacity.
- Based on 100% system usage, they do not reflect the change in the generation mix, the move to a low carbon mix that includes low load factor renewable generation.
- The demand and generation zone boundaries are different which suggest that neither demand nor generation tariffs can be cost reflective.
- The security factor is applied across the board, regardless of actual cost of system redundancy and failing to take into account the specifics of the existing generator's connection, arbitrarily doubling charges.
- The calculations are applied inconsistently –
    - Marginal investment costs are applied based on an expected future cost (forward-looking long run incremental cost)
    - Expansion factor is applied based on what infrastructure currently exists
    - Security factor is applied, regardless of what infrastructure currently exists, as a flat rate to all generators
- The assumptions are applied by National Grid such that in each case the extreme of the range of possibilities is used resulting in a worst case scenario for charges.

4.5 Volatile and Unreliable economic signals

The transmission charging methodology was originally meant to provide an economic signal to generators to indicate the best place to locate in terms of existing infrastructure availability. However, the variation in signals provided across GB is extreme, as illustrated by the table below.

Zone Name	2010/2011 Wider Tariff (£/kW)
North Scotland	20.08
Midlands	1.56
Central London	-6.41

When these charges are applied, the simple effect is that generators in Scotland pay significantly more for their use of the transmission system than those in the Midlands and are certainly not on a level playing field with generators in Southern England, who are subsidised for their use of the transmission system. The table below shows examples of wind, gas and coal generation in each charging zone.

Example technologies	Capacity (MW)	2010/2011 kW Charge (£m)
Wind	100	
North of Scotland		2.01
Midlands		0.16
South of England		-0.64
CCGT	750	
North of Scotland		15.06
Midlands		1.17
South of England		-4.81
Large Coal	2000	
North of Scotland		40.16
Midlands		3.12
South of England		-12.82

Taking into account that these charges have been shown (above) to be non-cost reflective, it appears that the only rationale behind such extreme variation is to strongly encourage generators to locate south of the Midlands. However, in practice, the economic signals do not have this effect for two reasons –

- Generators must take into account more than just the transmission infrastructure when deciding where to locate
- The locational signals are volatile and do not provide a stable basis for a significant investment decision

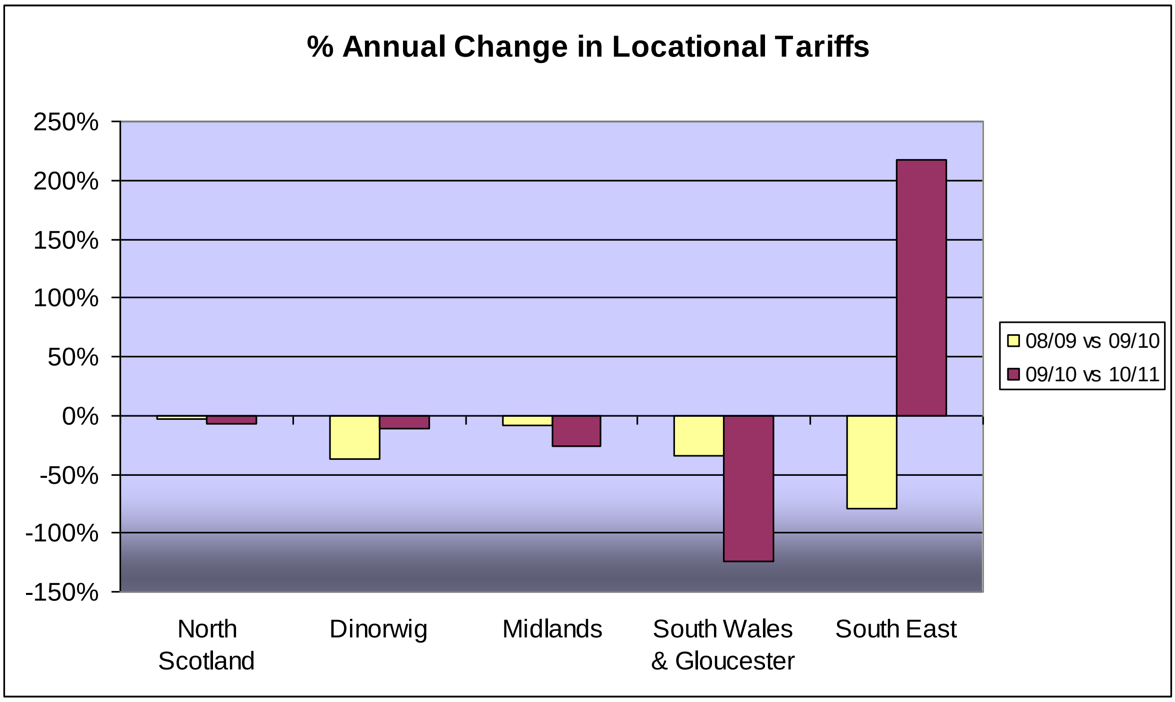
All generators have a wide range of factors to take into account when making the decision on where to locate. However, a key consideration is the availability of fuel. In the case of gas or coal as fuel, there may be some flexibility in location choice. However, for renewable generation, the plant must locate where the fuel source exists. For both wind and hydro generation, the best availability of "fuel" is in the northwest of Scotland, which incidentally has the highest locational transmission charge. The locational signals can have no effect on this type of generation and, as a result, the generator has no choice but to pay the highest level of transmission tariff (or not generate and go out of business). There is evidence that some developers are discouraged from certain generation projects due to the high cost of transmission charges. This has been transparently illustrated on the Western Isles and Orkney (as noted above). In discouraging these generators from connecting to the grid, the transmission charging methodology restricts competition and the resulting market prices are driven up.

However, the locational signals do not apply to all generators. Embedded generators, being connected to the distribution system, do not pay TNUoS and therefore do not respond to these locational signals. This generation is free to site wherever it decides, regardless of transmission tariffs. The current methodology creates perverse signals to generators to avoid the transmission network and instead size and site their generation sub-optimally to connect to the distribution system.

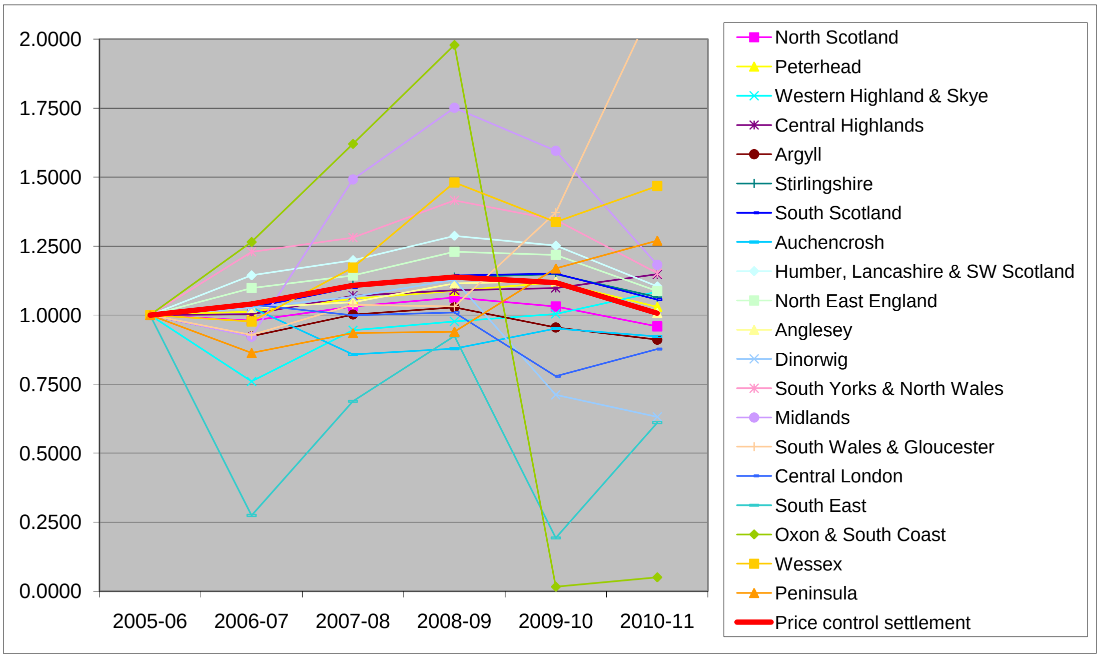
4.5.1 Volatility of tariffs

Even when a generator can respond to the locational signal, the volatility is such that the generator cannot be sure that the signal will not change in subsequent years, thereby undermining the initial investment decision. This volatility occurs in three areas – firstly, the normal annual change in tariff, secondly, the effect on the tariff of a generator's decision on location and thirdly through the addition of significant network investment.

The annual change in tariff has been significant in some areas over the last few years. For example, the 08/09 to 09/10 tariff change in Oxon & South Coast was a staggering 9,287% increase. One of our own stations, Hadyard Hill, saw its charges move from £5.61/kW to £12.90/kW, an increase of 130% between 06/07 and 07/08. The chart below illustrates some more moderate examples of year on year changes.



The graph below illustrates the change in tariffs across all zones since 2005/06, corrected for inflation and charted against the Price Control settlement. As can be seen, there are significant variations across the period.



The complexity and unknown inputs of the DCLF ICRP Transport Model used by National Grid to calculate locational tariffs makes it virtually impossible to predict tariff movement from year to year. As is clear above, not only do tariffs undergo significant change but they have a tendency to swing between positive and negative changes each year. Given this volatility of annual charge, it is difficult for generators to make informed decisions on the best location based on the signals presented to them. What may seem like a sound decision one year could then appear to be a costly decision the next. It means that investments cannot be robustly justified, even in the short term. This uncertainty over transmission charges leads to a premium being applied which adds to the cost of generation investments.

The second area of volatility is the effect on the tariff of a generator's decision on location. For example, if it were possible to relocate an existing 1500MW power station from the North of Scotland to South West England, the effect of the lost generation in Scotland would change the tariff from £21/kW to around £3/kW and the tariff in South West England would change from -£7/kW to around +£1/kW. This reversal of locational signal would immediately make it economic to locate in the North of Scotland. Thus when responding to the locational signal a prospective new generator has not only to assess the impact its commissioning will have on the transmission charges but also the likelihood of other investors responding to the same signal and the impact their projects will have in negating the benefits the signal indicates. This instability discourages investment in the UK compared to other countries with stable transmission charges. Such volatility provides unstable conditions for new generation investment and can adversely affect existing generators who cannot respond to a significant shift in transmission charge.

The third area where volatility can be seen is in the forward looking estimate of generator transmission charges provided by National Grid at the beginning of 2010 for the installation of the HVDC links or "Bootstraps". In this case, the level of charges that comes out of National Grid's ICRP model would more than double the charges in the North of Scotland. This will impact on both existing and new generation particularly in the North of Scotland. Of course, if no renewables were to get built then there would be no need for the bootstraps. It creates a Catch 22.

The practical effect of this volatility in charging is that existing generators in the North, both renewable and thermal, will close earlier than expected because of the high transmission charges. In the case of prospective renewable generators thinking about connecting in the North, the addition of the bootstraps would prevent them going ahead. The current transmission charging methodology does not provide the forward-looking and stable signals the industry requires in order to secure the high levels of investment required before 2020.

It should be noted that the design of the original transmission charging model for E&W considered the sensitivity of the model for various generation and demand scenarios. This included the addition of a medium sized power station, 1000MW, that resulted in a change in tariff that was less than £1/kW. Across the scenarios, the maximum change in the generation tariff was some £3.3/kW. The conclusion drawn was that the model was robust to input assumptions and those scenarios. It is clear that the existing model fails to meet these exacting standards on an ongoing year-to-year basis and more so when large-scale additions to the network to accommodate new renewables are considered, i.e. the bootstraps. If brought forward for implementation today, the model would be rejected.

4.5.2 Similar zonal constraint conditions, different tariffs

Although the transmission charging model is meant to provide a forward-looking indication of where investment on the transmission system is required, the current locational signals are inconsistent when constraint conditions are taken into account.

A review of National Grid's map of Average Cold Spell (ACS) power flows 2009/2010[5] shows significantly higher generation than demand in both the North of Scotland and the Thames Estuary regions. However, whilst the North of Scotland generation transmission charges are very high, yet more generation is actively encouraged into the Thames Estuary by low or negative transmission charges.

National Grid stated[6], in their SO Incentive Consultation 2009, that "The costs of resolving constraints within Scotland are currently forecast for 2010/11 at £110m." As illustrated previously, the transmission tariffs in Scotland are the highest in the UK, specifically to encourage generation to locate in areas closer to demand, thereby avoiding constraint costs.

National Grid then go on to state that "The cost of resolving the main constraint in the Thames Estuary is currently forecast for 2010/11 at £100m". The transmission tariffs in this area are mainly negative. In other words, generators are paid to locate there, despite the fact that additional generation is increasing constraint costs. It is questionable then whether or not the model is consistent with National Grid's licence obligations.

4.5.3 Similar forecast generation and investment costs, different tariffs

Another example of the dubious locational signals produced by the model is the comparison of forecast generation between Wales and Scotland.

The central scenario produced by the Electricity Networks Strategy Group (ENSG) assumes 8GW of new generation in Scotland and in excess of 7GW of new generation in mid and north Wales. The forecast capital cost of network investment to facilitate the connection of this new generation is around £1.5 billion in Scotland and around £2 billion in mid and North Wales. In simple terms, a similar volume of new generation at a similar cost for grid connection is expected in Scotland and mid and North Wales.

This, similarity in both the volume of new generation and the cost to build the additional transmission assets is however, not reflected in the TNUoS tariffs.

TNUoS Tariffs 2009/2010	New generation	Required grid investment	TNUoS tariff ('wider' only, £/kW)
Scotland	8 GW	£1.5 billion	11.24 – 21.59
Mid- and north Wales	7 GW	£2 billion	4.20 – 6.87

This clearly shows that whilst the level of new generation and cost of investment are approximately the same in the two areas, the TNUoS tariffs are markedly different.

4.5.4 Summary

The generation transmission tariffs produce volatile and unreliable locational signals

- Locational tariffs have an extreme range from £21/kW in North of Scotland to -£7/kW in South of England – this is not cost-reflective, distorts competition in generation and discourages investment.
- Historic tariffs display a percentage swing from year to year – in the past two years alone, some as much as +6% one year to -59% the next.
- Tariffs react to the locational decisions of generators, providing unpredictable prices for the longer term – Peterhead moving to Cornwall would change the Cornish tariff from a payment of £7/kW to a charge of £1/kW
- The tariffs predicted for the installation of the bootstraps are more than double the existing North of Scotland tariff. National Grid should not be working on investment in the bootstraps if they believe their own charging methodology.
- Tariff zones with similar constraint conditions display very different tariffs, thereby sending inconsistent signals to generators and increasing constraint costs.
- Tariff zones with similar new generation forecasts display very different tariffs, again sending inconsistent signals to prospective generators.
- Importantly, the methodology now fails the sensitivity criteria set for the implementation of the original model.

4.6 Distortion of retail competition

Whilst the system of locational charges subsidises some generators while excessively charging others, there is also a detrimental effect on retail competition.

For example, SSE pays approximately £90m per year for the use of the transmission system and uses 12% of the system's Transmission Entry Capacity (TEC). RWE pays approximately £3m per year for use of the transmission system and yet it uses 15% of the system's TEC. This inequity in transmission charging means that SSE have a significant and unavoidable additional cost to recover, which RWE are insulated from. Everything else being equal, both companies do not compete on a level playing field due to transmission charging.

Additionally, with the advent of greater integration of European markets, the differences between the transmission charging methodologies in each Member State exacerbates the tilting of the playing field. For example, a generator in South West Ireland pays lower transmission charges (approximately £6/kW) to supply a customer in the North of Scotland than a generator who is already located in the North of Scotland (paying approximately £22/kW). As cross border electricity supply increases, the excessive transmission charges paid by some generators in GB undermines effective competition.

4.7 Security of supply and the de-carbonisation of the electricity supply

There are several adverse side-effects of the current transmission charging methodology on security of supply and de-carbonisation.

Firstly, generation which is subject to high annual transmission charges is likely to run more intensively and then close earlier than expected to avoid ongoing transmission costs. This impacts upon the UK's impending "energy gap" as it introduces uncertainty into the generation forecast and ultimately puts pressure on security of supply.

Secondly, carbon intensive generation (such as oil-fired plant in the South of England) which receives ongoing annual payments to access the transmission system is likely to extend its lifespan, thereby keeping more polluting plant on the system in place of "greener" alternatives. Whilst this may appear to alleviate some security of supply concerns, the plant which stays on the system generally provides expensive peak cover rather than stable, baseload services.

Whilst the two scenarios above are a concern, perhaps the most significant unintended consequence is the potential destabilisation of the Scottish regional network. If locational signals endure and encourage new, fuel-flexible generation to locate in the South of England, non fuel-flexible renewable generation could be all that remains in Scotland. Once the existing gas, coal and nuclear plants close (which had all located in Scotland prior to the implementation of locational transmission charges), the Scottish network is subject to a prevalence of intermittent and relatively inflexible generation. Whilst there is no doubt that the UK needs this renewable generation in order to meet its 2020 targets, the network to which it is connected still requires stability in order to operate effectively. Without plant capable of providing on-demand power and ancillary services such as frequency response and reactive power, the network becomes susceptible to instability and frequency incursions. In other words, there becomes a much higher risk of the lights going out.

Of course, the Scottish network is part of a wider GB network and in the case of reduced generation capacity in Scotland, power would be provided by generation in England (this assumes that the network is capable of achieving similar flows South-North as exist North-South, however, this is currently not the case). However, this scenario contradicts the assumption that generation in Scotland outweighs demand and may reverse the existing locational signal, thereby making it economic for generators to locate in Scotland. This provides more uncertainty for long term investment decisions.

4.7.1 Summary

The current generation transmission tariffs produce unintended consequences for security of supply and decarbonisation of the electricity supply

- Generation in high charging areas closes early to avoid ongoing annual costs
- Carbon intensive generation that gets paid to access the system in the South continues to reap the windfall benefits whilst low carbon generation in the North is penalised
- The longer term reliance on mainly intermittent renewable generators in Scotland could destabilise the security of the Scottish network

4.8 The tariffs are at odds with EU legislation

Several pieces of EU legislation provide direction on the application and effect of transmission charging methodology. The existing GB charging methodology is at odds with much of this guidance.

4.8.1 *The Renewables Directive (2001/77/EC) and (2009/28/EC)*

The Renewables Directive of 2001, and also the recast of 2009, directs that –

"Member States shall ensure that the charging of transmission and distribution fees 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 regions of low population density."

However, the effect of the current GB charging methodology is that the highest transmission charges are applied to generators located in the North of Scotland, which is both a peripheral region[7] and a region of low population density.

4.8.2 *The Electricity Regulation (714/2009)*

The Electricity Regulation stipulates that –

"Charges applied by network operators for access to networks shall be transparent, take into account the need for network security and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operators and are applied in a non-discriminatory manner. Those charges shall not be distance related."

The GB transmission tariffs are not cost reflective. Additionally, the methodology incorporates a MW**km** cost based on the investment required for a MW to travel a given distance on the network. The outcome of this is a distance-related tariff which is directly at odds with the stipulated requirement that "charges shall not be distance related".

4.8.3 *ERGEG Transmission Tarification Guidelines 2005*

ERGEG completed a review of transmission tarification across Europe in 2005 and issued guidance to help national regulators and TSOs comply with European legislation. They specified that –

> 1.1. The value of the 'annual national average G' is annual total transmission tariff charges paid by generators divided by the total measured energy injected annually by generators to the transmission network. Annual average G shall exclude any charges paid by generators for physical assets required for the generators connection to the system (or the upgrade of the connection) as well as any charges paid by generators related to ancillary services or any specific network loss charges paid by generators.
> 1.2. The value of the 'annual national average G' must be within a range of 0 to 0.5 €/MWh, with the exception of the maximum values stated in 1.3 to 1.4 below.
> 1.3. The value of the 'annual national average G' within the Nordel system will be at a maximum 0.7 €/MWh.
> 1.4. The value of the 'annual national average G' within Great Britain, Republic of Ireland and Northern Ireland will be at maximum 2.5 €/MWh

Current national average generator charges are approximately €3.00/MWh which is outwith the derogation allowed for GB and significantly higher than the rest of Europe.

4.8.4 Summary

The current transmission tariff methodology is at odds with EU legislation in that -

- Its effect is to charge renewable generators in peripheral regions and those of low population density significantly higher tariffs than those in more central regions – this is prohibited by the Electricity Directive
- It is based on a distance-related calculation which is specifically prohibited by the Electricity Regulation
- It results in an average generator tariff which is outwith the tariff range specified in the ERGEG Transmission Tarification Guidelines 2005

5. Proposed Framework for Electricity Transmission Charging

Our proposed solution for electricity transmission charging brings together the following elements,

- a uniform commodity charge for the use of wider shared transmission assets along with a locational signal provided through a combination of
    - i) a local connection charge and
    - ii) potentially a locational transmission loss factor
- a fairer and more proportionate User Commitment

In relation to implementation, the original ICRP methodology was phased in over three years recognising that users may find it difficult to adjust to a change in their cost for transmission use of system overnight. Any fundamental shift in the methodology will similarly need to consider the implementation timetable.

This framework, based on a uniform commodity charge is in our view, more cost-reflective than the existing ICRP methodology. As we have presented above, we believe that the existing methodology cannot be shown to be cost-reflective. It cannot be shown to correctly allocate the costs of use of the transmission system to particular generation or to demand as it is not possible to know the costs sufficiently well to allocate them accurately and any calculation is extremely sensitive to key assumptions about system operation. The framework set out here seeks, rather than to fall into the same trap of inefficient and inaccurate allocation of costs, instead allocates these costs on an average basis.

The use of a uniform commodity charge is proposed here as there is strong evidence that the current locationally varying element of the tariff is no more cost-reflective than a uniform tariff approach. In considering the specific issue of the cost-reflectivity of the current TNUoS tariff, the correlation between TNUoS (specifically, the locational element) and transmission investment was examined in detail as part of the Transmission Access Review. The conclusion reached was that TNUoS is <u>not</u> a good proxy for network investment.

In addition, where charges cannot be shown to be doing what they are meant to, and are going against the public good by adversely impacting on new renewable generation and security of supply, a move to a uniform commodity charge that will allow the Government to better meet its renewable and climate change targets can be considered a public policy benefit.

Consequently, we believe that replacing a charge that is not cost-reflective with an average charge is a relative improvement, and the case is compelling when the many other benefits of a uniform tariff are also taken into account. An allocation of costs through a uniform commodity charge that is <u>right on average</u> is preferable to an allocation that that purports to be cost-reflective yet is <u>demonstrably wrong for everyone</u>.

There are already a number of precedents for uniform charging within the electricity market arrangements justified as achieving climate change and renewable objectives, or bringing an economic or societal benefit. For example, the charging of BSUoS was re-affirmed as being non-locational as part of the Government's review of the transmission access arrangements. This was based on an objective cost/benefit analysis, where the benefits of new generation connecting would outweigh the costs of constraints. Frequency response costs have always been charged out on a uniform basis regardless of the cost that different generators impose on the system. This again was re-affirmed, in the National Grid consultation in August 2010 on changing the loss limits. In its conclusions on the proposal, National Grid stated that "Maintenance of system frequency within defined boundaries provides security to all users equally and therefore is a common service with wider societal benefits". It can also be shown to be consistent with the majority of schemes across Europe.

This framework also moves away from a blind adherence to cost-reflectivity. Cost-reflectivity needs to be recognised as a means to an end, rather than an aim. The end should be the efficient investment in transmission infrastructure to allow the Government to meet its legally binding climate change targets. The methodology for charging for use of the transmission system needs to be considered in the wider context of meeting renewable and climate change goals and the framework presented here better meets those requirements.

5.1 Charging Regime

The framework for the charging regime would be based on:

- Wider shared transmission assets - for the parts of the transmission system used by both generation and demand users, a uniform commodity charge that is levied on generation users based on their measured export onto the transmission system.
- Generator only local assets - for those transmission assets used solely by generation user(s), a user-specific charge that reflects the upfront capital cost and ongoing maintenance cost of their local assets.

The combination of a uniform commodity charge (on a £/MWh basis) and a generator local asset charge would result in a locational signal that reflects the distance from the existing network rather than the distance from demand. Furthermore, negative charges would be removed. In addition, replacing the capacity reservation charge with a commodity charge would result in a reduction of transmission charges for low load factor generators and an increase in charges for high load factor users, better reflecting their actual usage of the transmission network over the charging year.

The rationale for this is simple. Local generator only transmission assets provide the physical link between the generator and the transmission system; without the generator these assets would be redundant. Given no other user benefits from the provision of local generator assets there it is clear that the connected user should be the one liable for the absolute cost of those assets. More importantly it means that the wider customer base is not exposed to inefficient or stranded generator only transmission assets.

In contrast, the wider transmission system has multiple users (both generator and demand users) resulting in power flows variable in both time and magnitude that are difficult to attribute to any individual user. In addition, the security and quality of supply standard for the wider shared transmission system is significantly more onerous than for local generator assets and, hence, in most instances the dependency of individual users on individual assets is tenuous. Given this, there is a strong case for charging users of the transmission system uniformly for actual use of the wider network.

5.1.1 Commodity Charge

Taking into account the predominance of high load factor, reliable generation, this has until now resulted in charges for use of the transmission system being levied on a capacity basis, i.e. a £/kW capacity reservation tariff.

Having been through a long period of relative stability in generating conditions, the GB electricity generation market is now going through a period of unprecedented change. Fossil-based generators are now subject to stringent environmental and emissions controls. Renewable technologies are encouraged and incentivised as a result of national and European policies and, increasingly, legislation. The future for nuclear generation in GB remains uncertain.

These, and other, factors have contributed (and continue to contribute) to significant changes in the operation of generation by users and, hence, their use of the GB transmission system. Whilst it is correct that investment in generator only local assets is scaled to meet peak export capability (and, through a local asset tariff, should be charged for on this basis), it is no longer appropriate to have investment in the wider shared transmission system charged out on the basis of meeting generators' peak export capabilities. This has been recognised by the transmission businesses and is a key consideration in the fundamental review of the SQSS planning standard.

Investment in the GB transmission system is increasingly being driven by the changing requirements of generation users. Overall, generation capacity is forecast to increase by around 40% by 2015. The volume of intermittent and low load factor generation has increased, and this rise is expected to continue. Against this background, demand forecasts are also changing in response to slowing consumer demand and increasing distributed generation; overall growth of less than 5% is expected by 2015.

Given, in particular, the changing operation of generation users and the growing plant margin (as the volume of low load factor intermittent generation increases), it is no longer appropriate or relevant to charge generation users for use of the wider shared transmission network on the basis of capacity reservation. Generation users will not all be able to respond to conditions of peak demand, and investment in the transmission system will no longer expect this. There will be a significant excess of generation connected to the system as new renewables connect but existing plant remains open to cope with the variability of renewable generation. Generators will be sharing transmission network access on an energy basis and so should share the costs of its use on the same basis.

A move to a commodity charge would assist fossil fuel generation with low load factors to remain available on the system for peaking operation. It would also be more appropriate for other peaking plant, particularly pumped storage plant (whose transmission charges can be 50% of their lifetime costs) that will be needed to cope with the intermittency of renewable generation. In addition, a commodity charge will provide a better signal to generators on when to generate or not. As more supported renewable generation enters the market, there will be a greater numbers of half hours when the market price goes negative. A commodity charge as opposed to a capacity charge will help reduce these instances. This in turn is also likely to reduce constraint costs. If applied to the demand side, a commodity charge would provide a better signal to customers to reduce consumption.

Hence, we believe that the prevailing conditions are more suited to a charge for generators which is based on utilisation, a commodity charge.

5.1.2 Uniform Charge

For the reasons described below, we believe that the utilisation charge for transmission should be levied as a uniform charge across GB (as a whole) determined from the total annual revenue generation requirement (£) divided by the total annual generation export (MWh). Each generator user would be liable for the utilisation charge multiplied by its total metered export over the year.

Such a charge would be transparent, predictable and stable; hence, facilitating effective competition in generation. It would recognise the developments in the GB electricity generation market and use of the transmission system, and the consequential changes to the way the transmission licensees run their businesses.

We recognise that the key concern around implementing a GB wide utilisation tariff will be the loss of the locational signal and, in particular, the impact on cost reflectivity of removing the locationally varying element of the tariff. It is true that a uniform tariff would represent an average charge and, hence, would not exactly reflect an individual user's impact on the costs of the transmission network.

However, as noted above, there is strong evidence that the current locationally varying element of the tariff is no more cost-reflective than a uniform tariff approach. Consequently, we believe that replacing a charge that is not cost-reflective with an average charge is a relative improvement, and the case is compelling when the many other benefits of a uniform tariff are also taken into account.

Considering the specific issue of the cost-reflectivity of the current TNUoS tariff, the correlation between TNUoS (specifically, the locational element) and transmission investment was examined in detail as part of the Transmission Access Review. The conclusion reached was that TNUoS is <u>not</u> a good proxy for network investment. To illustrate this, National Grid presented the example of reinforcements to the shared transmission system necessary to connect new generation near London. Once connected, the new user would be liable for a negative TNUoS charge yet, to provide the connection, investment of £70/kW would be required.

In response to this, it is argued that, although transmission investment is required to connect the near London generator, the overall cost of connecting this generator is negative because an equivalent sized generator further from London is no longer required, i.e. demand requirements can be satisfied by the new near demand generator, removing the need for the costly remote transmission system. This argument takes no account of the long life of existing generation and transmission assets. While it might be credible in times of low plant margin, the validity of the argument is stretched for intermittent and low load factor generation users (which are forecast to increase substantially over the foreseeable future). We do not believe it is cost-reflective to attribute a negative charge to, for example, an offshore windfarm located near London that requires many millions of pounds of transmission investment to connect and yet makes a negligible contribution to security of supply.

A cost-reflective allocation of the costs of the wider shared transmission network is best achieved, in our opinion, through a uniform commodity charge. Alternative approaches to allocating the costs will not be cost-reflective when considered over the lifetime of generation and transmission assets, not least as power flows become more variable in response to the changing generation mix and a growing plant margin. For example, over the lifetime of a plant there are two significant decision points, the first when they decide whether or not to make the investment, the second some 40 years later when they decide whether or not to close the plant. In between, the current methodology imposes costs that are volatile year–on-year and particularly with large infrastructure investments and cannot be shown to be accurate. In contrast the actual costs of the network are relatively stable over the lifetime of the generator and infrastructure assets. An allocation of costs through a uniform commodity charge that is <u>right on average</u> is preferable to an allocation that that purports to be cost-reflective yet is <u>demonstrably wrong for everyone</u>.

5.1.3 Liability for the local and wider charge

All generation users connected to the GB transmission system would be liable for the local and wider charges. Embedded generators with a BEGA would be liable for the wider charge only.

The generator only local asset charge would be determined for each generation user and comprise a circuit and substation element. The wider shared asset charge would be determined annually from the known revenue requirement and a forecast total generation export. Generation users would be charged monthly for the previous month's metered export.

Whilst our views on the failings of the current transmission charging methodology apply equally to demand-side tariffs; the impact on competition in supply is less acute given that all suppliers face the same transmission charge for any individual customer and the main driver for change to the charging methodology is moving to a low carbon generation sector. So whilst in principle we have no objection to the framework proposed here being applied to both generation and demand across GB, it is put forward and described here in its application to generator charges only.

5.1.4 Impact of a uniform commodity charge

The total revenue recovered from generation users in 2010-2011 is around £430 million. If a generator only local asset charge was introduced (covering local and offshore specific costs), this would recover around £90 million. We propose that the remaining £340 million would be recovered through a uniform commodity charge for use of the wider shared transmission assets.

Based on information in the public domain, we estimate that the combined impact of the local asset and wider commodity charges would be a reduction in transmission charges for around 60% of generation users, including all renewable generators. Of those generation users that would experience an increase, we estimate that less than 10 users would experience an increase of more than £5 million per annum (of which, the majority are currently liable for negative charges).

The main impact of the combined local asset and wider commodity charges would be the introduction of stability and predictability in transmission charging. This, we believe, would be welcomed by an industry that is required to make significant long-term investment and indeed operational decisions in the coming years.

The investment in new generation required is clear, but the stability and predictability of the charging arrangements affects existing plant, for example, the operational decisions at an aging thermal plant that has opted-out of the Large Combustion Plant Directive. This user has to decide how to profile the use of its remaining operational hours between now and 2015. The current transmission charging regime encourages early use of the hours as the charge is based on capacity not use, and there is uncertainty about future charges. Local asset and wider commodity charges would provide certainty over costs and not penalise the generation user for its low load factor.

5.1.5 Locational Transmission Losses

There have been proposals to change the existing uniform transmission losses scheme to a locational or zonal transmission losses under the market arrangements (both the Pool and the BSC) since the late 1990s. BSC Modification P229 is the latest incarnation of this and is currently before the Authority for decision.

The implementation of a zonal losses scheme would replicate the locational signal inherent in the current transmission charging methodology. Clearly, a double locational penalty would be both discriminatory and disproportionate. Double locational charging in this way would lead to even greater distortion of the market and a greater adverse impact on generation in Scotland. This potential inefficiency was acknowledged by Ofgem as long ago as 1999[8]. Ofgem also noted at that time the practical benefits of reviewing both transmission charging and the charging for transmission losses at the same time. We agree with this position and would urge that this approach is adopted by Ofgem at this time. Indeed, we strongly believe that a decision on BSC Modification P229 should not be made until the review has concluded. We will continue to resist the imposition of a zonal losses scheme <u>in combination</u> with the existing ICRP methodology.

Nevertheless, whilst the framework described above includes a locational signal given by the local connection charge, the framework would sit comfortably with a zonal transmission losses scheme and could provide a more proportionate signal for a more efficient dispatch, if not for location.

5.2 Reform of FSL and User Commitment

The second most significant issue for new generators connecting to the transmission system is the level of liability they have to underwrite to National Grid. Securing such large liabilities is excessive in a Connect and Manage world where there is little risk of stranding of main infrastructure asset costs, adds to the cost of new entry and as such creates a barrier to entry and the development of some projects. This barrier exists under both the Final Sums methodology and the current interim Generic User Commitment methodology (IGUM).

In our framework we propose that the Final Sums methodology be reformed. In addition, whilst a move to a uniform commodity use of system charge as we have proposed here will reduce the level of User Commitment under IGUM, and make it more equitable across GB, the current 10 year's worth of TNUoS charge remains unnecessary and disproportionate. We propose that 2 years would be appropriate and consistent with the commitment that existing generators pay for exiting the system. Reform of the User Commitment arrangements in this way would remove a significant barrier to new renewables being connected.

Reform of the FSL should be based on the following principles:

- Maintaining the FSL requirements for local works, but with a fairer allocation of liabilities on the basis of contracted capacity as a proportion of the capacity of the reinforcement;
- Given the significant reduction in the stranding risk for wider works following the recent transmission access reform, replacing the ex-ante allocation of the liabilities associated with wider works with an ex-post mechanism to recover incurred stranded asset costs from all generation users, and
- As a proportionate user commitment, introduction of a minimum requirement for FSL equal to two-times the prevailing average generation wider use of system tariff (e.g. two-times the £/MWh for the last charging year, times the planned plant size (CEC) utilising the average GB generation load factor for the last charging year).

We also propose that the definitions of "local works" and "wider works" are aligned with the definitions used in the 'connect and manage' style access arrangements, but supported by an ex-post recovery mechanism and a 'floor' on generator FSL. The main change under this approach would be the removal of the requirement for ex-ante securitisation of wider works. This change is consistent with the significant reduction in the stranding risk for wider works that is a consequence of the recent reform of transmission access. Given this access reform, the current FSL arrangements for wider works cannot be shown to be cost-reflective or proportionate. We believe that the actual risk of stranding of wider works under the new transmission access arrangements is insufficient to justify the cost burden and competitive barriers imposed by ex-ante underwriting.

We set out our preferred approach in more detail below.

5.2.1 The clear definition of transmission reinforcement works as "local" or "wider"

Interim Connect and Manage (ICM) has introduced the concept of local infrastructure works as being the minimum works required for connection. This concept has been carried forward into the recently introduced enduring Connect and Manage (C&M) arrangements under the new terminology of "enabling works". We support a clear, consistent definition of transmission reinforcement works as "local works" (under C&M, "enabling works") or "wider works" that would apply to both the transmission access regime and FSL arrangements.

5.2.2 *Allocation of the liabilities associated with local works based on contracted capacity as a proportion of the capacity of the reinforcement*

Currently, local works are secured either 100% by the associated generator or pro-rated by Transmission Entry Capacity (TEC) where a number of generators share the reinforcement. This can result in situations where transmission-connected generators provide security for new transmission capacity required by embedded generators or for strategic network development. This is a recognised unfairness of the current FSL arrangements that places a disproportionate burden on a subset of prospective generation users. We propose a direct, 'pound-for-pound', securitisation of local works where liabilities are allocated either:

- where there is a single generator, based on the ratio between the capacity of the minimum works required to provide the connection (for that single generator) and the capacity of the reinforcement, or
- where there are a number of generators, based on the ratio between the contracted capacity (TEC) of each generator and the capacity of the reinforcement.

Hence, for example, two generators of 100MW each that are securing a 250MW reinforcement of £2.5 million would, in the future, be allocated FSL of £1 million each. The balance of £0.5 million would not be allocated to these two generators acknowledging that this additional 50MW of capacity is required for other reasons (for example, to accommodate distributed generation). This approach would be consistent with the current transmission connections charging methodology. We support the existing six month security period for local works.

5.2.3 *No ex-ante allocation of liabilities associated with wider works*

The implementation of ICM has revealed the difficulties in maintaining cost-reflective FSL arrangements when generators' connections are no longer contingent on the completion of wider works. This situation has been exacerbated by the implementation of C&M, and is further complicated when pre-BETTA applicants, embedded generators, offshore transmission and potential strategic investment in the network (e.g. the bootstraps) are taken into account.

Consider an, admittedly extreme, scenario: generator group A are contingent on reinforcement X, and generator group B are contingent on reinforcement Y that succeeds reinforcement X. Generator group B connect under ICM and their pre-connection liabilities fall away. No securities are now being provided for reinforcement Y. There is a strong case for progressing reinforcement X to alleviate operational constraints caused by the connection of generator group B. Reinforcement X is constructed and is secured by generator group A during construction. On completion of reinforcement X, the associated liabilities fall away from generator group A who have still to connect. The FSL arrangements need to be reformed such that they are fit-for-purpose under ICM (and C&M). This fundamental mismatch, and the resultant perception of unfairness, need remedied.

One option to maintain the cost-reflective link between generator and wider works would be to continually 'juggle' the contingencies on wider works to match connection dates. While in principle this approach is cost-reflective, it would be, we believe, a mammoth task to maintain such FSL arrangements for wider works under

ICM and C&M. This task would be made even more difficult if demand variations (due to embedded generation and/or changes in consumption) were to be taken into account. The administrative costs (system planning and contract management) alone would place an unreasonable burden on the industry. In addition, this would introduce significant uncertainty into the contractual arrangements for generators not least because it would very difficult to forecast future FSL.

Given this, we do not support this approach and have concluded that it is not practically possible under ICM and C&M transmission access to maintain a cost-reflective link between wider works and contingent generation. Moreover, as we describe below, we do not believe that this link is appropriate.

FSL are a form of insurance; insuring transmission licensees (and, ultimately, consumers) against the risk that assets become stranded during construction – that is, after construction the assets are recognised to be over-sized and of no system value. In addition, that the developer of a new generation project is prepared to secure FSL provides a signal to transmission licensees that the developer is 'serious'. This was an important consideration under the old Invest and Connect access regime whereby construction of the long lead time transmission reinforcement must have commenced before, and in some instances a long time before, generation projects had commenced. In these circumstances, the stranding risk was high and full 'pound-for-pound' securitisation by the contingent generation was argued to be appropriate. That said, we are not aware of any circumstance where there has been construction of transmission assets that are identified, post-construction, as being stranded. We note that during the development of the (CUSC) transmission access changes in 2008, no examples of this post construction stranding of transmission assets since privatisation, could be identified by National Grid.

However, in contrast to, for example, car insurance, FSL does not currently incorporate an assessment of risk. In effect, it assumes that there is 100% stranding risk associated with every wider works investment (even though there have been no examples of this happening since 1990). Hence, pre-connection generation users are required to secure every penny spent on wider works. This is the case even where wider works contribute to demand or when contingent generation are already connected.

One of the advantages of ICM and C&M is that the risk of stranded network transmission assets is greatly diminished. This has already been acknowledged, in particular in respect of where wider works are associated with a derogated boundary then no securities would be required. It is argued that there is limited stranding risk for works necessary to restore the system back to compliance. This is comparable to what was agreed when pre-BETTA applicants were not required to provide security for reinforcement of the B6 transmission boundary between Scotland and England.

The principle should be, in our view, that securities should only be required where there is an actual risk of stranded transmission assets – and the security required should be proportional to the risk. In our view, it is this principle that should underpin the calculation of generator liabilities. The issue then is what is the stranding risk associated with wider works under ICM and C&M.

We believe that the stranding risk is negligible. There are three key reasons for this. Firstly, as described above, the majority of wider works are now being, and are likely to continue to be, driven by a requirement to restore the transmission system back to compliance (with the SQSS). Secondly, the onus will be on the transmission licensees to demonstrate, before commencing works, that there is a strong needs case. As described in Ofgem's Enhanced Transmission Incentives workstream, this is a prerequisite of being allowed to recover the costs of reinforcement. Thirdly, as noted above, since 1990 there have been no examples of this actually happening.

Given this, it would clearly be disproportionate and not cost-reflective to continue to require full 'pound-for-pound' securitisation from generators against a risk that does not exist or is very small. Hence, and once the wider implications are taken into account, we believe that no ex-ante securitisation of wider works on the transmission system is required.

Removing the requirement for ex-ante securitisation of wider works would be more cost-reflective (where the cost is not the cost of the wider works but cost of the potential stranded asset) and would also facilitate competition. The current requirement to secure FSL for wider works places a large cost burden on prospective generators. There is the direct cost levied by financial institutions for providing, for example, the necessary letter of credit to National Grid. This is a particular issue for smaller generators which typically have a poorer credit rating and so pay a higher cost to the financial institutions. These liabilities then (visibly or not) sit on the balance sheet of the generator tying-up capital that might otherwise be invested in new generation. Removing the unjustifiable financial burden of FSL for wider works would, we believe, have a beneficial effect on competition.

5.2.4 A Fairer and More Proportionate User Commitment

The current 10 year's worth of TNUoS charge remains unnecessary and disproportionate. We propose that the introduction of a minimum requirement for FSL equal to two times the prevailing average generation wider use of system tariff would be appropriate and consistent with the commitment that existing generators pay for exiting the system. Reform of the User Commitment arrangements in this way would remove a significant barrier to new renewables being connected.

5.3 Summary

The benefits of this framework can be summarised as follows:

- It would provide a simple, clear and transparent basis for charging that would be easily understood by all market participants. The current ICRP methodology by contrast is complex and difficult for users to use.
- As a result of its simplicity, it would be capable of being implemented quickly.
- It therefore stands the best chance of delivering the Government's renewable, climate change and security of supply targets.
- A uniform charge would be stable and therefore predictable. Predictability over investment timescales would provide greater certainty for generation and network planning and investment decisions. The ICRP methodology is anything but predictable.

- All generators would pay the same rate for accessing the transmission system regardless of technology, size or location. This would facilitate a 'level playing field' in the energy market. The proposed model would also ensure that renewable energy is not the subject of discrimination in terms of charging, especially from more remote areas as stated in the Renewables Directive. The existing ICRP methodology creates an uneven playing field both within GB and with other markets.
- Implementing such a change would not change the total revenue recovered from the charges paid by generators to National Grid. It is also important to note that demand consumers need not be affected by this change. The generator charge would be of the order of £1/MWh.
- A commodity charge would recognise the characteristics of different generation technologies, in particular the load factor. Such factors are already being acknowledged in transmission network planning and operating assumptions, and hence transmission network investment.
- By comparison with the ICRP methodology a uniform commodity charge is more cost reflective. Cost-reflectivity is a means to an end, rather than an aim. The end should be the efficient investment in infrastructure to allow the Government to meet its legally binding climate change targets. This framework would better meet this objective.
- This change would remove a key barrier to renewable generation in areas where such resources are greatest, while also sending a stronger signal to consider replacement investment in thermal baseload. It would also be compatible with 'Connect & Manage' which requires sharing of capacity rather than reserving capacity for the sole use of that generator.
- The changes proposed for FSL and User Commitment will remove a barrier to the development of new generation.
- This change would be a step towards integration with the wider European energy market and compliance with European charging guidelines. The majority of European markets use a form of uniform charging. The transmission tarification guidelines published by the European Regulators Group for Electricity and Gas (ERGEG) advocate harmonisation of use of system charges for generator across Europe. To achieve this, there is a strong case for reducing the wider shared transmission asset charge in GB for generation towards zero.

We believe that this framework will better meet the Government’s and Ofgem’s goals for moving to a low carbon generation sector.

5.4 Implementation

Many of the generation stations (at least 13GW) affected by these changes will have closed under LCPD by 31 December 2015. Their actual date of closure will be influenced by both their TNUoS charges in those later years and the fact that they will receive their final EU Emissions Trading Scheme allowances (the final allowance would be received for being open on 1st January 2012 therefore they could close on 2nd January 2012). All other fossil fuel generation will be affected by the final allocation of EU ETS allowances and therefore there may be additional plant closures before 2015.

The original ICRP methodology was phased in over three years recognising that users may find it difficult to adjust to a change in their cost for use of system overnight. Any fundamental shift in the methodology will similarly need to consider the implementation timetable.

6. Endnotes

[1] NERA Study, 2004

http://www.nera.com/image/200408ReviewofGBwide.pdf

[2] Proposed 126MW wind development in Orkney, Fairwind Orkney Ltd

In November 2006, NGET indicated to Fairwind Orkney Limited that the TNUoS tariff for its proposed 126 MW windfarm development would be £113.90/kW. The current tariff for the north of Scotland is £20.93/kW; hence the indicative tariff is around £93/kW over-and-above the mainland tariff. The capital investment required to install a subsea transmission link from the north of Scotland to Orkney has been estimated to be around £90 million (see, for example, the NGET information paper published in July 2005 to support the DTI consultation *Adjusting transmission charges for renewable generators in the north of Scotland*). The equivalent annual cost of this link (including financing, operation and maintenance costs) can be calculated using the annualisation factor in NGET charging methodology. The annualisation factor is 0.084; hence the equivalent annual cost of this link is £7.56 million or, for the Fairwind development, £60/kW. NGET's indicative tariff, derived from the DCLF ICRP transport model, is over 50% greater than that estimated using NGET's own parameters for the capital investment requirement, financing and operating costs.

[3] Media links to the cancelling of Fairwind project in Orkney

http://www.orcadian.co.uk/archive/2009/archive12.htm

[4] Proposed 300MW wind development in Shetland, Viking Energy

In late 2006, Highlands and Islands Enterprise engaged the consultants TNEI to study options for grid connections for the Scottish islands. An element of TNEI's work was to consider the likely TNUoS charges that would be levied by NGET. Although the report has yet to be finalised, TNEI has estimated that after the establishment of a subsea link the TNUoS tariff on Shetland would be around £42.1/kW over-and-above the prevailing mainland tariff of £20.5/kW. This estimate is broadly consistent with the indicative tariffs published in the DTI's consultation *Adjusting transmission charges for renewable generators in the north of Scotland* (July 2005). In this document, the Shetland TNUoS tariff was estimated to be in the range £20.1-61.5/kW over-and-above the mainland tariff. In contrast, NGET has indicated to Viking Energy, the developers of a 300 MW wind power station on Shetland, that the TNUoS tariff might expect after the construction of a subsea link will be around £120/kW over-and-above the mainland tariff. NGET's indicative tariff, derived from the DCLF ICRP transport model, reflects an increment of around three-times that estimated by TNEI from the actual capital and operating costs of the link.

[5] National Grid ACS Power Flows 09/10 – Fig 7.3

http://www.nationalgrid.com/uk/sys_09/default.asp?action=mnch7_6.htm&Node=SYS&Snode=7_6&E=Y

[6] National Grid SO Incentive Consultation – P.109 Item 3.6

http://www.nationalgrid.com/NR/rdonlyres/519DEB34-5CCE-40D6-9980-9DE23A41E666/38228/ElectricitySOIncentivesInitialProposalsConsultatio.pdf

[7] Map of European Central and Peripheral Regions

Source:
http://ec.europa.eu/regional_policy/sources/docoffic/official/reports/pdf/mapa4.pdf

[8] Extract from: *NGC System Operator Incentives, Transmission Access and Losses Under NETA: A Consultation Document*; Ofgem, December 1999.

Introducing the marginal pricing of losses will result in signals being provided to participants of the short-run marginal costs of electricity transmission. Currently, the TNUoS charges provide signals as to the long-run marginal costs of electricity transmission. Both the proposed losses scheme and the TNUoS charges provide locational signals and, given the interactions between short run and long run marginal costs, it may inefficient to expose participants to both sets of locational marginal costs charges. Hence, it may be appropriate, when introducing a new transmission losses regime to revisit the method of calculating TNUoS charges so that they are exposed to a consistent set of short and long-run signals and charges. The introduction of a new transmission access and pricing regime will, in any case, require TNUoS charges to be revisited and we believe that the impact of marginal losses should be considered at the same time.

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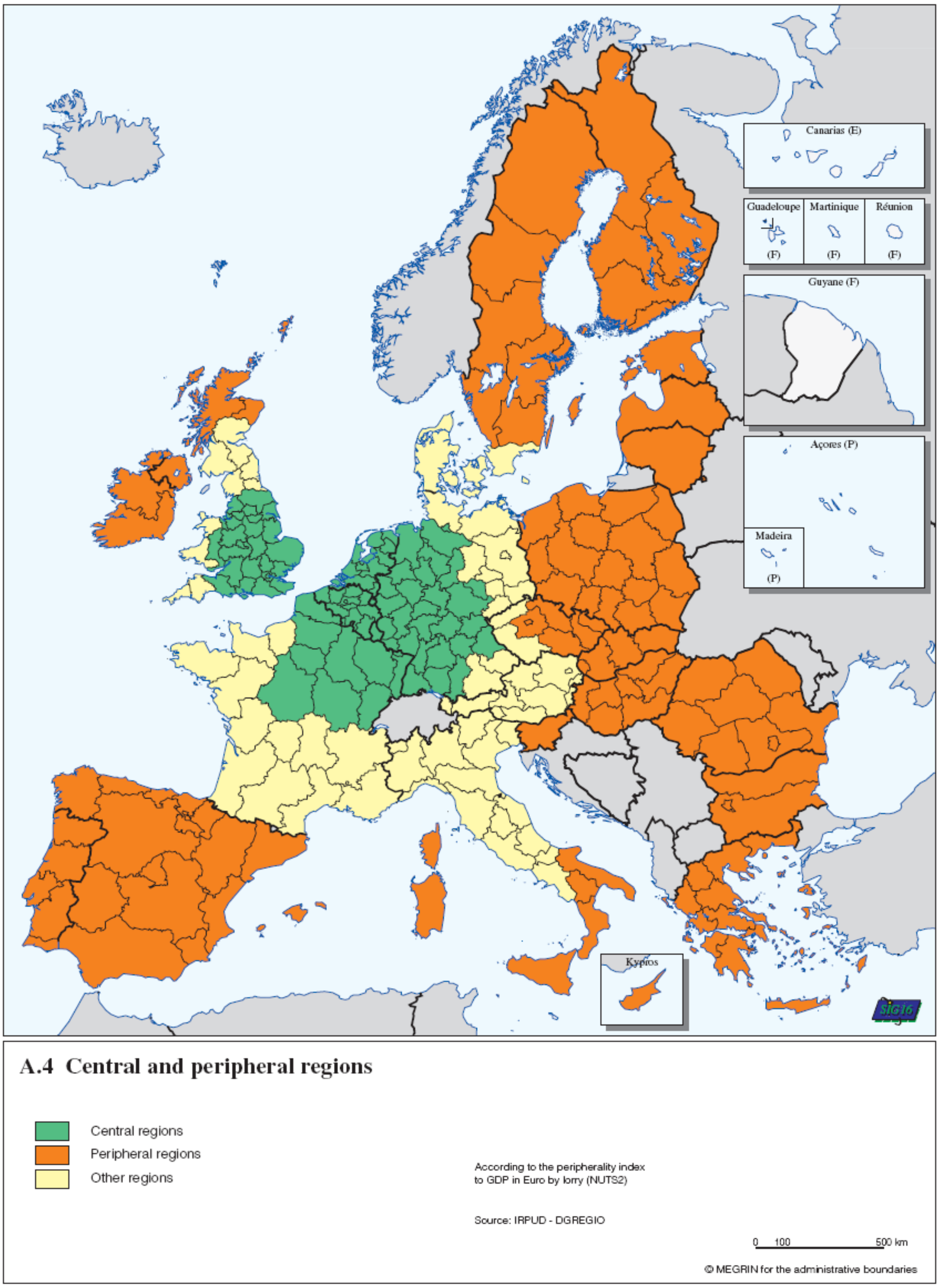

Map of GB Transmission Tariff Zones

Source: http://www.nationalgrid.com/uk/sys%5F09/chapA/images/figA-1-3.pdf

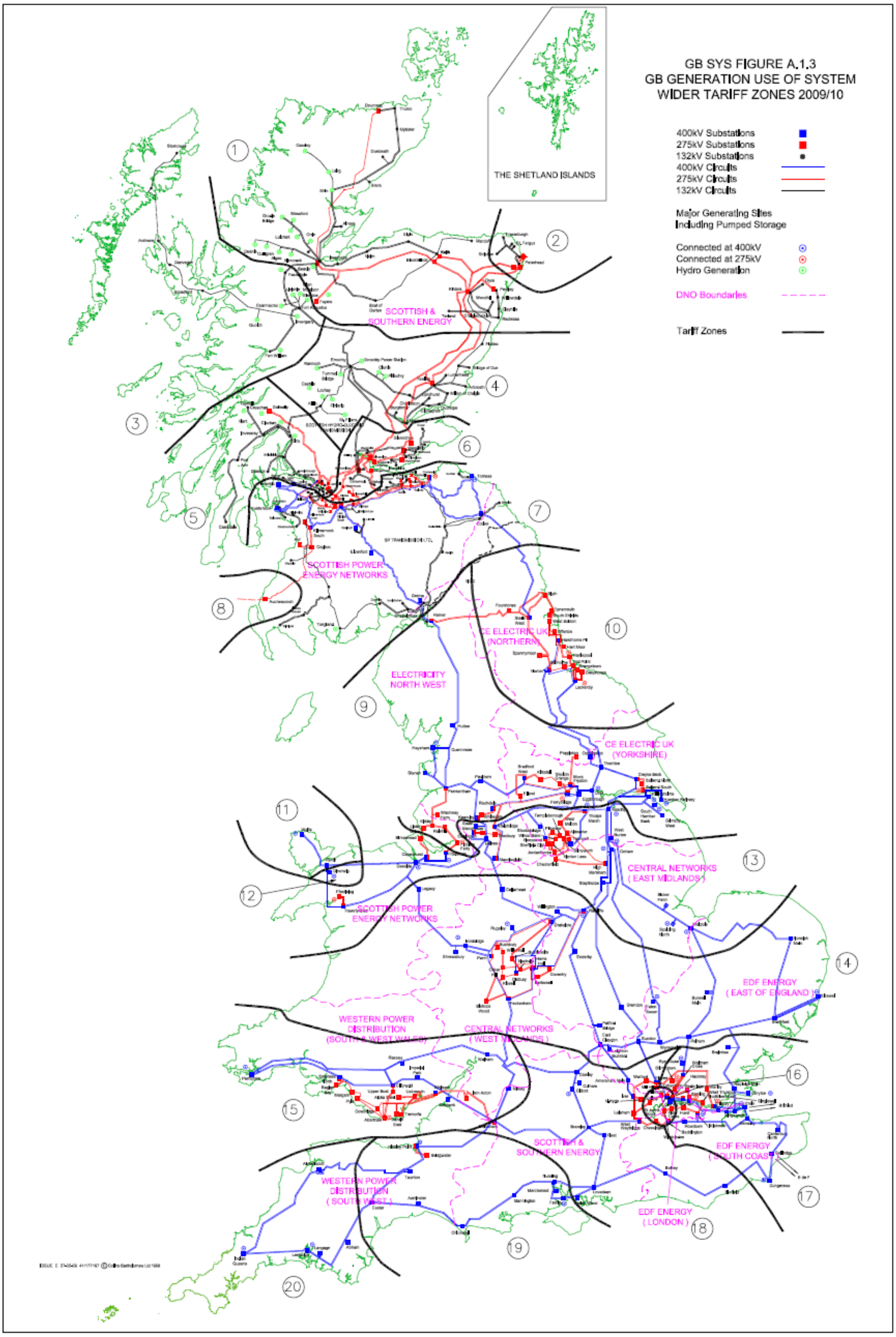

Table of GB Transmission Tariffs

Source: http://www.nationalgrid.com/NR/rdonlyres/0782D36F-3270-4FC2-9787-5B8EDA358441/31610/NoticeofTNUoSTariffs2009_10.pdf

Zone	Zone Name	2008/09 Tariff (£/kW)	2009/10 Tariff (£/kW)	Tariff Changes	
				Absolute	%
1	North Scotland	22.26	21.59	-0.67	-3%
2	Peterhead	19.76	20.32	0.56	3%
3	Western Highland & Skye	20.53	21.10	0.57	3%
4	Central Highlands	16.74	16.87	0.13	1%
5	Argyll	15.06	13.99	-1.07	-7%
6	Stirlingshire	14.36	14.48	0.12	1%
7	South Scotland	13.52	13.60	0.08	1%
8	Auchencrosh	10.38	11.24	0.86	8%
9	Humber, Lancashire	6.32	6.14	-0.17	-3%
10	North East England	9.95	9.85	-0.10	-1%
11	Anglesey	6.83	6.87	0.04	1%
12	Dinorwig	9.82	6.19	-3.63	-37%
13	South Yorks & North Wales	4.42	4.20	-0.22	-5%
14	Midlands	2.32	2.11	-0.21	-9%
15	South Wales & Gloucester	-2.47	-1.60	0.87	-35%
16	Central London	-5.66	-6.98	-1.32	23%
17	South East	1.22	0.25	-0.97	-79%
18	Oxon & South Coast	-0.01	-1.39	-1.37	9287%
19	Wessex	-2.57	-3.28	-0.71	28%
20	Peninsula	-8.53	-6.68	1.84	-22%