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Dear Colin,

Enduring transmission charging arrangements for distributed generation

Thank you for the opportunity to comment on the above consultation document. E.ON UK appreciates that a review of present arrangements for transmission charging may appear appropriate given the increasing amount of distributed generation which is being built or planned. However, we would urge that Ofgem carefully considers the effects that any changes may have both on existing investments and the incentive to invest in the future.

The principle underlying the present market structure is that it is suppliers who are responsible for trading activity within a GSP Group. Therefore, generators below a certain size located on a distribution system are deemed to be netting against local demand and the supplier is responsible for the commercial implications of this. This affects the design of the settlement arrangements under the Balancing and Settlement Code (BSC), the treatment of transmission losses, as well as the charging methodologies for transmission use of system charges.

Simply put, transmission connected generators are responsible for trading at, and transporting their output to, the 'National Balancing Point' (NBP) on the transmission system and therefore pay the appropriate charges such as TNUoS, BSUoS and transmission losses. Suppliers are responsible for taking generation from the NBP to their demand using the transmission system and distribution networks. They therefore

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pay TNUoS, BSUoS, transmission losses, distribution charges and losses. Suppliers are also responsible commercially for distributed generation which may reduce both the amount of power traded at the NBP and the amount which needs to be transported across the transmission and distribution networks.

It was decided to make suppliers responsible on a GSP Group basis. This was largely done for practical purposes. It would have been possible to make suppliers responsible for what happens at each individual GSP. However, this would have involved more complex settlement calculations and would have required arbitrary decisions such as allocating the demand of certain customers to particular GSPs, when it is arguable that they were being supplied from more than one GSP (or that the GSP could switch in response to changes in local conditions). Therefore, distributed generators are allocated to GSP Groups and settled in the demand data of the relevant supplier at this level too. They are not allocated to individual GSPs.

Industry participants have made and continue to make investment decisions on the basis of this policy decision. We therefore believe that the existence of a significant problem needs to be illustrated in order to justify a change to the current arrangements. Otherwise, there is a risk of sufficient disruption to the market and a subsequent lack of confidence from investors. In the present climate, further disincentives to invest in new power generation would be highly damaging.

We will address the main issues in the consultation in turn.

Exporting Grid Supply Points

We agree that an increase in the amount of distributed generation will make it more likely that individual GSPs will export at times. However, we are not sure why this necessitates a change to the charging methodology. If the system is based on what happens at GSP Group level then we should not be concerned as to what happens at individual GSPs. Indeed, central systems do not measure what happens below the GSP Group level.

To be concerned solely with exports at individual GSPs also risks inequitable treatment compared with demand. Clearly, different importing GSPs use the transmission system to different extents. However, it is the total demand of the GSP Group which is taken into account for demand TNUoS charging. A change to consider exporting GSPs on an individual basis would logically require the same approach for importing GSPs.

The two potential issues raised in the consultation document were National Grid's ability to obtain the information it needs to operate the transmission system and the cost reflectivity of charges.

National Grid has for some time been concerned by the increasing impact that distributed generation may have on the transmission system. This has resulted in a number of amendments to the CUSC being raised culminating in amendment proposal CAP097 which is presently out for industry consultation. Regardless of whether the degree of concern is justified, we cannot see how a change to the charging methodology can provide National Grid with better information regarding likely physical flows on its system.

We agree that it is possible to argue that all generation capacity, both transmission and distribution connected, makes some use of the transmission system and therefore should pay some form of transmission charge. However, as we mentioned above, a policy decision has been taken to allow certain distributed generators to be netted off against demand within GSP Groups. Different assumptions could have been made. There is no one correct answer to how the underlying principle for the market should have been chosen. What is important though is that the resulting arrangements are consistent with the principle chosen.

We are not convinced that the present charging arrangements result in a significant problem for the market such as the distortion of competition in generation. The present arrangements are generally consistent with the concept of embedded generation netting against local demand on a GSP Group basis. There have been notable exceptions such as the approved BSC modification P100, which would result in embedded generators obtaining benefits even if an entire GSP Group were to export. However, generally the arrangements are consistent with the principle of aggregation at GSP Group level.

In the absence of evidence of a significant problem, we believe that changes to the methodology should be minimised so as not to undermine confidence in the market.

The choice of voltage at which to connect

There appears to be two concerns here. The first relates to the different voltages regarded as transmission in Scotland compared with England & Wales. The second relates to incentives for generators sometimes to connect at distribution level rather than to the transmission system.

Much has been made of the fact that generators connected to 132kV assets in Scotland are treated differently to those connected at the same voltage in England & Wales. However, there is no reason why this should be a problem. The voltage at which they connect is irrelevant to the commercial arrangements that they face. It is purely an engineering concept. The relevant consideration is the licensed activity for which the wires are being used. If a generator is connected to the transmission system then it should pay transmission charges. Likewise a distribution connected generator should be liable for distribution charges. If 132kV wires are being used for the licensed activity, then we see no reason why generators connected at that voltage should be exempt from paying transmission charges. We therefore continue to believe that the discount given to 132kV connected generators in Scotland is a source of distortion in the market, rather than a solution to a problem.

In the case of generators choosing to connect to a distribution network rather than the transmission system, it is not clear why this is an issue either. A decision to connect will take into account a number of factors. One of these will be the trade off between the cost of connecting to the transmission system compared with a connection to the local distribution network. This will entail comparing not only the cost of the connection assets, but also the relevant use of system charges.

The paper appears to imply that it is inequitable that distributed generators, who could be using the transmission system, do not pay transmission charges. However, it is possible to argue that transmission connected generators use distribution systems to transfer their generation to the end customer and should therefore also pay distribution charges. However, we would not advocate such a change as this would also not be consistent with the basic principle which underpins the present market structure.

The choice of generator size

The concern here appears to be that market participants will choose the size of their embedded projects so as to avoid transmission charges and that this gives companies a perverse incentive. It is clear that this incentive exists. However, it is not clear why this should be seen as a problem. Generators may be giving up economies of scale by choosing projects of certain sizes, but these are commercial decisions made taking into account all relevant cost drivers faced by the company concerned.

We agree that any limits set on the basis of size are arbitrary. However, generators have made, and continue to make, investment decisions based on these limits and we believe that it would potentially be more damaging to market confidence to change the system without a good reason for doing so.

Potential changes

Not withstanding our doubts as to the existence of a problem with the present system, our comments on the proposed options for change are as follows.

De-energise a plant that ‘causes’ a spill at a GSP

We agree with Ofgem that this would be a disproportionate response. It is also not clear how a particular generator could be tracked back to a specific GSP. This problem is one of the reasons that SVA systems aggregate at the GSP Group level. Additionally, it is perfectly possible for a GSP to export as a result of a change in demand. Therefore, this could result in action being taken which was inequitable as well as impractical.

Amendments to the charging model

We are a little unsure as to what changes would be made to NGC’s transport model to ‘better’ model conditions on the 132kV part of the network. The 132kV network is already accounted for through the use of 132kV specific transmission factors in the charging methodology. We are also disturbed by the statement in the paper that more a cost reflective approach could render the discount obsolete. It appears that there is a preconception that a more cost reflective approach would result in a reduction in the charges for 132kV assets. This has not been proven and indeed the present discount has been justified not on the grounds of cost reflectivity, but on the basis of inequitable treatment of generators on similar voltages, which we do not believe is a relevant consideration.

Extend the DCLF ICRP model to parts of the distribution network

As we have mentioned above we do not believe that the voltage of connection is a relevant consideration when deciding whether or not a party should pay transmission charges. If the ICRP model was extended into parts of the distribution system it would introduce uncertainties as to the boundary between transmission and distribution charging. Additionally, distributed generators on the voltages concerned could equally complain that they were being discriminated against compared with other distributed generators.

Amend the use of size definitions as the basis for charging and contractual arrangements

As we mentioned above, by definition limits on charging based on size of generator will be arbitrary. We therefore cannot see how a change in the definition would be any less arbitrary.

There is however a more worrying aspect to this proposal. Presumably, the intention would be that more generators would be forced to seek a Transmission Entry Capacity (TEC) before they could connect to the distribution system. The potential increase in TEC applications would add an additional burden to an already extremely difficult situation regarding the assessment of the vast number of applications that presently exist.

Creating a consistent liability for charges

The proposal to expose both transmission and distribution connected generators solely to the locational element of TNUoS charges could be a legitimate approach to transmission charging. However, this is still a significant departure from the methodology which has underpinned many existing investment decisions and presumably also some suppliers' purchasing decisions in respect of distributed generation. We are concerned that the degree of change this represents is not justified in the absence of evidence of a significant problem with the existing arrangements.

Agency models

We do not support the concept of an agent acquiring TEC for an exporting GSP on behalf of the 'relevant' generators. This has the same issues in respect of inequitable treatment of generation and demand where demand is treated on a GSP Group basis and generation on an individual GSP basis. It would also be difficult to apportion the subsequent cost to individual generators. Additionally, the export could have been caused by a change in demand as much as a change in generation.

It could also result in the double counting of the generation in two opposing ways. At present a supplier's GSP Group demand is reduced by the presence of embedded generation. This results in a reduction of its liability for demand charges. If the same generation was also charged for exporting via an agent, then this would be logically inconsistent and would distort the signals in the market. The only alternative to this would be to remove the 'offending' embedded generation from the supplier's GSP Group demand. This would require a significant change to BSC Settlement systems. The case for change would have to be strong to justify such expenditure.

Conclusions

We are not convinced that there is strong need for change of the present methodology. The present methodology is largely consistent with the principles which underpin the market arrangements. Many of the changes proposed would have a significant effect on the market and could greatly reduce investor confidence in a climate which is already difficult for new investment in generation.

Changes which could be made however to reduce distortions in the arrangements are the removal of the arrangements brought in by BSC modification P100 and the abolition of the subsidy awarded to generators connected to the 132kV part of the transmission system in Scotland.

Yours sincerely

Paul Jones
Trading Arrangements