Mr Stuart Easterbrook
Transmission Charging Development Manager
Commercial
National Grid Company Plc
NGT House (Floor C3)
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

Friday, 14 May 2004

Dear Stuart,

The following comments are made on behalf of RWE Innogy plc, Innogy Cogen Ltd., Innogy Cogen Trading Ltd., npower Ltd., npower Northern Supply Ltd., npower Yorkshire Supply Ltd, npower Northern Ltd, npower Yorkshire Ltd, National Wind Power

GB Transmission Charging: Initial Methodologies Consultation

RWE npower welcomes the opportunity to comment on the issues contained within the Initial Methodologies consultation for GB transmission charging published on the 8th April 2004.

In Summary

RWE npower supports a GB use of system charging methodology with the following key features:

TNUoS

- A representative DCLF model
- Scaling of injection capacities to approximate peak merit order
- Forward looking expansion constant reflective of full incremental cost of increasing power flows
- Multiple-voltage expansion factors representative of incurred costs
- Locational Security Factor
- Zonal range of no greater than +/-£1/kW
- Phased reduction of G/D split

BSUoS

- Zonal Balancing Services Prices

RWE npower supports the development of economically efficient locational signals across both the transmission and distribution networks. In the context of the significant expansion of renewable generation, predictable and cost-reflective tariffs must be developed to provide appropriate locational signals for both directly connected and embedded generation, with symmetrical signals for demand. These will ensure that investment in infrastructure assets is efficiently incurred, and that the costs that users impose on the networks are recovered from those that cause them to be incurred. At a time when a large quantity of potential generation is deciding where to locate, it is more significant than ever to have correct locational signals.

The Draft Guidelines on Transmission Charging relating to the European Commission's Regulation on Cross-Border Trading propose a transitional regime whereby harmonisation of average generator use of system charges must occur by 2008. There is therefore a window of three full GB charging years before harmonisation. A uniform progression from the current G/D split would provide a solution to negative demand tariffs whilst preserving cost-reflective locational signals. However, any proposed movement in the G/D split should be publicised well in advance to ensure that its impact on charges is predictable.

TNUoS Charging

Usage of data in the DCLF model

Discussion of the treatment of interconnectors and intermittent generation in the DCLF model has highlighted that the uniform generation scaling method employed in the current E&W TNUoS methodology does not produce a set of nodal generation values that are reflective of peak conditions. We support the application of scaling factors for all injection points, including interconnectors, approximating the peak merit order as this would produce nodal generation values that are more representative of peak conditions. The resultant tariffs would therefore more accurately reflect the investment required to transport peak flows on the system.

NGC has suggested that it will not be possible to replicate the existing E&W methodology of using TECs as nodal generation input data as all GB bilateral agreements will not be completed at the time the tariffs are calculated. However, the current England & Wales methodology requires the use of forecast TECs as opposed to extant TECs. Forecast TECs for Scottish generation units have been implied within the scenarios presented in the Addendum to the Initial Thoughts Consultation. NGC should make this list of forecast TECs comprehensive and ensure its publication. This would allow the relevant owners the opportunity to refine as necessary. This would have the further merit of informing NGC's

consultation on the allocation of entry access rights for GB. We would urge NGC to set out in unambiguous terms the timescale to be followed this process.

Negative demand charges

The multi-voltage expansion factors were introduced into the E&W model from 1st April 2004 in order to reflect better the normal operation of the system, it would be a retrograde step to exclude this feature from the GB methodology purely for the purpose of eliminating negative demand charges. Moreover, we would challenge whether reverting to a single voltage expansion factor would improve the stability of charges. Whilst it may eliminate negative demand charges for 2005/06, this may not be the case in subsequent years.

If it were considered necessary to eliminate negative demand charges, varying the recovery of the non-locational element of the tariffs via a phased reduction of the G/D split would produce a coherent and predictable evolution of charges without compromising the cost-reflectivity of the methodology. The alternative would seem to be a series of arbitrary and temporally unpredictable distortions, starting with the single voltage approach employed in Scenario A. This would seriously undermine the charging methodology principles and increase the regulatory risk faced by investors.

Zoning

The current zoning criterion of +/-£1/kW has been in place since the start of the ICRP methodology in 1992. Its declared purpose is to make charges more stable and simplify administration. However, it creates the potential for unpredictable tariffs due of the large number of permutations satisfying this criteria based on the differentials in the nodal shadow costs for both the current E&W model and the proposed GB model. A smaller range would decrease the number of permutations and associated subjectivity in determining the zones, thus increasing the predictability of tariffs. A nodal generation tariff approach would offer improved cost-reflectivity and predictability of use of system charges. It would also remove the need for NGC to examine numerous zoning permutations and choose from these using opaque selection criteria. Whilst there is maybe a trade-off to be struck between predictability and volatility in choosing between nodal and zonal charges, a widening of the range would be wholly counterproductive to the pursuit of the relevant objectives.

Forward looking expansion constant

An expansion constant based on MEA rather than historic values would appear to be the appropriate approach for calculation of the marginal costs of infrastructure investment. However, the current E&W expansion constant of 9.21 is artificially low as it ignores investment in transmission equipment such as

transformers, quad boosters and SVCs which is driven by power transfers across the network. Whilst the requirement for some of this investment is not directly proportional to power flows, equipment such as circuit breakers and protection systems are an integral part of every transmission scheme. The cost of all transmission equipment used in power transfers should therefore be included in the expansion constant.

Reconciliation of pre-BETTA over/under recovery

Any under or over recovery of 2004/05 use of system charges in E&W should be recovered from an E&W charging base. Similarly, any under or over recovery of 2004/05 use of system charges in Scotland should be recovered from a Scottish charging base.

BSUoS Charging

Ofgem's open letter on access to the GB transmission system on 4th May stated that 'significant transmission constraints could exist from BETTA Go-live'. The level of these constraints is likely to rise further as applications to connect new generation in the north of GB increase to meet the Government's targets for renewable energy.

Currently, BSUoS is charged on a postage stamp basis despite the fact that it recovers System Operator external costs that are to a great extent locationally driven. The most obvious locational costs include the cost of constraints resolution via Balancing Mechanism actions, NGC Forward Trading and the cost of reactive power procurement. However, the requirement for other balancing services, such as warming contracts, Black Start and system-to-system services are also partially driven by location. Under a postage stamp BSUoS charging structure, overall costs of system balancing are likely to rise as a consequence of siting and despatch decisions failing to take adequate account of system balancing costs.

NGC should therefore review as a matter of urgency the potential to develop cost-reflective locational BSUoS pricing. BSUoS costs are already temporally categorised into those that can be assigned to a particular period and those that cannot. These costs could be further categorised into those that are locational and those that are not. Where some there is some ambiguity regarding the categorisation for a particular type of cost, a proportion of the cost could be included in the initial locational cost grouping and this could be subject to refinement in subsequent iterations of the methodology.

A model could be designed to calculate the marginal variation in the locational costs for increments of generation or demand in a number of defined zones.

These could be calculated ex-ante based on a representative sample of periods. The mechanism could be similar to that developed for the locational transmission losses scheme proposed in BSC Modification P82. Ex-ante zonal Balancing Services Factors could be multiplied by the ex-post BSP to produce zonal Balancing Service Prices. Such a methodology would facilitate NGC's licence obligations with respect to the allocation of access to the transmission system and ensure that this is achieved at minimum cost to the consumer.

Please do not hesitate to contact me should you wish to discuss any of the issues raised above. We would be pleased for this letter to be published and hope it will assist in the further development of the GB transmission charging methodology.

Yours sincerely,

Shona Watt
Transmission Charging Manager
npower