

Charging Issues Standing Group

Minutes: 6th January 2010

This report outlines the key discussions and actions of the CISG meeting. All presentations, agendas, meeting notes and future meeting dates are available at the CISG web page of the National Grid Industry Information website at <http://www.nationalgrid.com/uk/Electricity/Charges/cisg/meeting/>

ATTENDEES

Hêdd Roberts	National Grid (Chair)	Peter Waghorn	Cornwall Energy Associates
Pat Hynes	National Grid	Paul Jones	E.ON
Ivo Spreeuwenberg	National Grid	Michael Dodd	ESBI
Sarah Hall	National Grid	Rachel Fowler	NPower
William Kirk-Wilson	National Grid	Dafydd Elis	Pöyry Energy Consulting
Wayne Mullins	National Grid	Richard Ford	RES
Nick Pittarello	National Grid	Tim Russell	Russel Power
Louise Schmitz	British Energy	Garth Graham	SSE
Ricky Hill	Centrica	Helen Snodin	Xero Energy

1 Condition 5 publication –long term forecast of TNUoS

National Grid presented the major points in the Condition 5 report¹ that was published prior to Christmas. National Grid noted that the draft tariffs for 2010/11² were also published. The major difference between these two figures is the inclusion of National Grid's assumption on OFTO revenue (the draft tariffs include £84m OFTO revenue). In terms of the forecast 10/11 tariffs the main changes to zonal tariffs were explained, these were mainly due to changes in forecast generation positions. National Grid noted that in publishing final tariffs at the end of January it expected to publish two sets, with and without locational BSUoS adjustments.

In terms of the Condition 5 forecast the changes 10/11 are as described for the draft tariffs. For Scotland, in 11/12 the main difference is due to the effects of embedded generation and specific larger generation projects. In 12/13 the major effect is increased generation in Scotland. In 13/14 the main change is due to the expected commissioning of the Beaulieu Denny and further increases of generation in Scotland. It was noted that if parts of the Beaulieu Denny reinforcements become cable this would have a significant impact on tariffs.

For changes in England and Wales, there are inherent changes due to the increased flow from Scotland and a number of changes year on year due to increases in pockets of renewable generation projects and notable large generation projects.

In response to question National Grid confirmed that the draft tariffs for 10/11 include the assumption that offshore 'go live' will be in June 10. Therefore any adjustment within year relates to errors in National Grid forecast of OFTO revenue and not the actual introduction of OFTO arrangements. National Grid noted that it had very limited information in respect of OFTO revenue financing arrangements. A number of members indicated that on first reading of the consultation they had taken the within year change to be that associated with introduction of OFTOs i.e. the initial tariff not containing any OFTO revenue. National Grid agreed to clarify this is the publishing of final tariffs

¹ <http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/>

² <http://www.nationalgrid.com/uk/Electricity/Charges/usefulinfo/>

It was noted that the Condition 5 report did not include offshore ENSG HVDC reinforcements i.e. it only includes reinforcements identified in the SYS. There were a number of question about whether TNUoS was robust against large-scale reinforcements. It was noted that the G/D split has a significant impact regarding the residual i.e. even through the generation differential was cost reflective demand would pick up 73% of the absolute cost, and where there were large investments (e.g. offshore) this will always have an impact. National Grid indicated that it had consulted extensively on Offshore large reinforcements and that it believed the methodology itself is robust, although there was an outstanding issue about the competitive tender process (notably in association with transitional projects) where assumptions needs to be made.

In terms of charges to the residual it was noted that the main beneficiaries were onshore generation whose residual reduces, larger in proportion to its charge than to the offshore generators, and that the differential between generators is maintained. Also, that the main impact was on demand who were required to pick up 73% of the absolute revenue requirements through demand residual.

It was noted that as interconnector flows change this could have an impact on charges in term of TEC and demand assumptions in the model (for demand National Grid forecast the peak flow). National Grid noted this was an area that needed to be investigated given the expected changes to interconnector flows. It was also noted that how wind is modelled is also very import important. A further issue that needed further clarification and / or investigation was the background to assumptions on embedded generation, National Grid noted that currently it uses used DNO submission as provided in the SYS unless it has more accurate data.

National Grid noted that the draft tariffs were based on 60% of the OFTO costs being socialised. National Grid would investigate if it could publish further information on this.

2 Charging for HVDC

National Grid presented the issues that the 'bootstraps' raise in the methodology. The main issues are: Should the parallel HVDC interconnectors be included in the DCLF? And if they are included, how should their expansion factors and impedance be determined ?

It was suggested that National Grid could consider a nominal, average or peak based forecast to determine equivalent impedance. The impedance determines how much flow is transmitted by the cables. National Grid presented a graph which demonstrated the relationship between flow on the cable and the tariff in Scotland. National Grid indicated it would provide information on western and eastern links separately.

It was asked if it was appropriate to charge for strategic investments. National Grid suggested that strategic investment was market driven and a reasonable test could be the willingness of users to pay for investments to show that they are efficient. The development of investment signals for TOs is an area for discussion in other forums.

It was noted that the inclusion of HVDC cables in the system was possibly a large change and this may be considered as part of the ongoing work on volatility. It was noted that timing, planning permission and current over allocation also influence the planning decision. It was noted that further analysis should also show the effect on demand.

It was also suggested that if Scotland imported at peak, because expected wind was not running, this would have an impact on the tariff. National Grid indicated that how wind was modelled at peak is an important issue that needs to be investigated, but it is also important to consider that if it is appropriate for wind to have a peak based or whether a KWh based approach is important. It was noted this comes back to how we plan for wind – peak based or year round which would be discussed in a later presentation.

3 Application Fees

National Grid noted that it sent an industry letter on proposals to revise the structure of application fees in November. This presentation highlighted the background to the proposals and sought any further thoughts to be considered before proposals were finalised.

It was suggested that the capacity threshold bands could be merged as according to the regression results, the main step change in costs arises at the >1320MW category. It was argued this should be the driver for the thresholds, not the distribution of application capacities.

It was questioned whether there could be a time component i.e. for offers far in the future may not have as much works completed for the offer initially. National Grid indicated that at some point before commissioning extensive works would need to be completed.

It was noted that some costs were not size based, National Grid indicated that the fixed element was intended to cover this. It was asked if the proposals were applied to last years applications would this recover more or less. National Grid confirmed it had not carried out analysis in this area. It was also questioned whether offshore costs were included in the tender or not, National Grid agreed to check this issue.

It was noted that the application fees associated for the SHETL area were significantly lower versus the existing fees. National Grid stated the analysis was based mainly on smaller applications but it was challenged whether the boundaries of influence map suggests TO increments would also be appropriate in addition to the core fee. It was also questioned whether under proposal 3 a premium was appropriate. Following discussion it was agreed this was related to combining new and mod app fees, National Grid agreed to consider this further.

A further issue raised was the lack of transparency with variable cost. National Grid welcomed specific suggestions on how it could improve information.

4 Within year charging changes

National Grid presented proposals on how to deal with within year changes to tariffs. This issue has arisen due to the mid year introduction of OFTO revenue requirements, that through the tender process National Grid will not have information available to set accurate tariffs in the timescale required, i.e. the tariff are published prior to the tender process being available.

It was noted that this is mainly a transition issue where the revenue requirements occur very close to the OFTO licence being awarded. In terms of size of issue it is approximately £76m +/- £16m for 10/11.

National Grid highlighted the three main options in the consultation. It was suggested that National Grid was central to the process and could better forecast the costs, also as National Grid is regulated there would be a lower risk premium for the Industry overall. National Grid indicated that this was an amount that would be a significant Kt level. It was suggested that the OFTO revenue adjustments could be treated as a separate kt adjustment to avoid passing through existing Kt arrangements. It was also noted that changing charges within year was more cost reflective. It was suggested that for offshore generation, and possibly onshore generation as well, could manage these changes better than Suppliers.

The issue and impact on National Grid was understood, but the general response was that National Grid was better placed to manage this, although it was accepted that for offshore generators publishing mid year tariff was expected. National Grid maintained concern that this was not a cost it was managing (it was an offshore tender process issue) and whether it should manage it and how it would be funded was a further issue.

5 Offshore embedded transmission

National Grid provided some background to the issue and reviewed the proposal to be consulted upon shortly. The key question is whether generators connected to embedded transmission should they be treated as embedded or directly connected, and whether this issue should be resolved before or during a wider review of embedded generation.

6 Embedded generation

National Grid gave a presentation why it is taking forward a review and why the embedded generation benefit arises within current charges and discussed whether this reflected the true benefit of embedded on transmission.

It was suggested that Industry representatives should include some DNO charging and smart grid representatives. National Grid agreed and would approach relevant groups to request representatives. National Grid indicated that the effect on transmission is similar between an embedded generator and a directly connected one, and there is a financial incentive to embed for generation less than 100MW. The example used was if a supplier contracted with embedded generation in Glasgow, but sold the power to customers in Edinburgh. The supplier obviously uses the transmission system, however TNUoS is not charged as both the generation and demand are in the same DNO zone. The total value of this “embedded benefit” was forecast to be £265m a year. National Grid’s view was that this was discriminatory and distorted competition in generation. Furthermore, in exporting areas it leads to a perverse signal where embedded generators are being paid to connect, even though TOs were making transmission investments partly due to increasing embedded generation.

To remedy the distortion, the Gross Nodal Supplier Agency Model (GNSAM) would separate out suppliers’ demand into generation and demand components, so instead of a embedded generation netting off against demand, the separate components would be brought out and charged separately. There are variants and a pre-consultation will be published exploring the alternative models for implementation by April 2011.

It was suggested that £265m was in fact an underestimate as it did not include large generating stations less than 100MW.

7 Wind Charging

National Grid reviewed the work that it had undertaken to look at the relative costs of wind compared to other units. The results of the analysis suggested that the efficient level of investment for wind would be less than the efficient level required for a gas generator. This is because wind generators tend to generate at a lower outputs than conventional plants so are less likely to cause a constraint when they generate. In this analysis wind has a bid price of -£50 some members of the group considered the bid price could be substantially greater. National Grid agreed with this statement and considered that this was one of the key assumptions which would continue to be reviewed during ongoing work, although work was ongoing to understand why wind is currently bidding a extremely high prices.

Some members of the group suggested work on charging for wind should follow on from the SQSS review of planning for wind. There was concern that analysis on charging could head in a different direction to the SQSS review and it was important that the two were linked. One member of the group noted that the current scaling for which takes place under network planning was not reflected in the current charges. National Grid noted that they were moving to using the same model as colleagues involved in the SQSS review and suggested it was important that the reviews take place in parallel. National Grid also noted that changes, including for technologies other than wind, could have an impact on access rights and in particular on trade TEC arrangements and flexibility.

6 A.O.B.

Helen Snodin questioned whether the zero cap on demand charges was still appropriate. Along with this a further element is whether the Island should be split out on a GSP basis. Associated with this National Grid also noted that it has received a letter from Ofgem who have received correspondence from EUROELETRIC and ETFET with regard to Triad charging. National Grid is required to respond to Ofgem by end of January and set out a timetable for works. National Grid would propose to include negative demand charging in this review. It was noted the one of the main reasons for the cap was to avoid perverse behaviour. Embedded generation was also noted as an important factor here and the possible incentives need to be reviewed.

It was noted that there was a significant interaction with registration MPANs in BSC. It also suggested that if special island demand zones were created this would send a precedence and there could be call for other new demand zones, be they exiting connected island i.e. if you disaggregate in principle where do you stop. In terms of the capping issue comments should be sent to Helen Snodin. It was noted that there was a universal tariff obligation on Suppliers with respect to Northern Scotland, this would also need to be considered.

Dates of future meetings to be held at National Grid House, Warwick:

24th February, 2010

28th April, 2010

30th June 2010