

Notes on G3 workshop 13th June 2007

Attendees:

Haz Elmamoun	E.ON
Edward Coleman	E.ON
Glenn Sheern	E.ON
Jane Griffith	Central Networks
Andrew Neves (AN)	Central Networks
George Moran (GM)	Central Networks
Maria Liendo (MIL)	Scottish Power Energy Networks
Tony McEntee (TM)	Scottish Power Energy Networks
Stuart Andrew	Scottish Power Energy Networks
Garth Blundell	Scottish Power Energy Networks
Andy Manning (AM)	Npower
Max Lalli (ML)	SSE Power Distribution
Mo Sukumaran (MS)	SSE Power Distribution
Nigel Bessant (NB)	SSE Power Distribution
Robin Hodgkins (RH)	Consultant (Mathematical & Computing)
Nigel Lloyd (NL)	Western Power
Pat Wormald	CE Electric UK
Collette Schrier (CS)	Ofgem
Bernard Kellas	Scottish & Southern Energy
Simon Brooke (SB)	United Utilities

Morning Session

Introduction

AN welcome everyone to the workshop and explained the purpose and what G3 hoped to achieve.

Consultation Section 3: Forecasting Future Reinforcements

NB presented on the method used to forecast future reinforcements. He explained the concept of network groups, highlighted their importance in network analysis and demonstrated first-circuit outage and second-circuit outages (N-1 and N-2) contingency analysis. He also detailed similarities and differences between demand and generation studies.

SB asked if the method of determining reinforcement requirements for 33kV and above used any other standards (i.e. internal standards) other than the publicly available standards listed (LTDS, P2/6, G74, Distribution Code). It was clarified that, for transparency, the methodology worked only to the listed standards.

NL queried why incremental approach adopted in the contingency analysis stopped at 15%. G3 responded by pointing out that performing contingency analysis by incrementing load in 1% steps up to 15% was appropriate to capture the potential reinforcements required within a 10 year time horizon. SB pointed out that in some parts of United Utilities region, growth was much greater than this and that stopping

at 15% would not be appropriate for them and asked whether there were any similar high growth areas in the G3 networks. G3 responded by saying that they were comfortable that 15% was appropriate for the G3 networks but also that the 15% cut off point (or the 10 year recovery period) could be revised in future if it ever became necessary.

SB queried whether the N-2 analysis was being applied correctly. NB explained that P2/6 identifies N-2 requirements for class D and class E groups. N-2 analysis is considered under situations during the maintenance period and that the maintenance period was assessed as being 67% of peak demand.

SB also queried how we dealt with network groups that were connected to each other and it was clarified that if two or more GSPs run in parallel then they would be treated as a single network group (as an example MS indicated that the SEPD area had several supply points operating in parallel and that each parallel group was considered to be single Network Group).

SB queried the G3 assumption that generators would connect to the bars of the principal substation of the network group and asked whether there was any supporting data to back up the assumption. He pointed out that this was not his experience in the UU area and would not be true for the Cumbrian region. NL also said that wind farms, for instance, generally required long lengths of line to connect. TM/NB responded by pointing out that it was their experience that generators connected in this way, and that even where this was not the case the assumption was still valid for charging purposes as generally the network costs for lines would be recovered by connection charges as sole use assets – as such it would not be appropriate to recover them again in the UoS charges.

Consultation Section 4: Determining Forward Looking Costs

RH explained the basis behind the mathematics used in determining forward looking costs. He explained the reasoning for choosing 10 years as the time horizon for the analysis. The aim was to utilise spare capacity on the network now and therefore discouraging demand because a demand forecast indicates capacity might be exceeded in 20 years time was not appropriate. Increasing levels of DG and load growth forecasts in general mean that long term load forecasting is likely to be inaccurate. Furthermore, reinforcements over longer periods depend increasingly on previous reinforcements which are not included in the current modelling process. He explained that 10 years was not a 'magic' number but that it was arrived at by balancing the need to provide customers with enough time to react to cost signals and using forecasts that were reasonably reliable to produce those cost signals.

SB commented that the reinforcement sequence was very important and also that in practice reinforcements may be made that are greater than required because it is more efficient to perform a large reinforcement in one stage rather than two separate reinforcements separated by just a few years as the model may indicate is necessary. G3 agreed with this point and said that the larger reinforcements coming from the model were sense checked for this possibility.

NL then asked why we use multiple time periods – why not simply charge for the period of demand that is causing the reinforcement. RH explained that there were two

main reasons why marginal charges were not limited to the single time period with the greatest maximum demand. First, the demand can fluctuate depending on weather or due to growth (if the load is the same for all time periods but grows at say 2%, then maximum demand will fluctuate between winter and summer as the season progresses with each exceeding the previous maximum by about 1%). So a band is needed rather than a sudden switch from one time period to another. Second, demand had evidently shifted in some network groups away from the traditional peak period to other times. If the signal to avoid traditional peak periods was removed, then substantial amounts of demand could move back in to the traditional peak period. These swings are potentially large (although they would presumably be damped by energy prices), especially when suppliers use teleswitching. The proposed method gives zero marginal costs for all time periods where the capacity would not be exceeded within 10 years (eg. period 5 on the slide) and it is only as the demand in each period approaches capacity that marginal charges are incurred. The proposed method also has the advantage that it is a single approach applied consistently to all time periods giving the level of stability that G3 believe is required.

NL also queried why the EHV customers were charged on a per kVA basis given all the analysis that was undertaken to quantify the costs in different time periods. G3 indicated that at this time a per kVA basis is considered to be appropriately cost reflective but could be reviewed as part of the longer term model development.

CS questioned the appropriateness of a 10 year cost recovery period. She felt it should be longer. RH responded by pointing out that we are only including the costs that are expected to arise over a 10 year period and it is therefore appropriate to recover those costs over the same period. TM echoed this view that the period used for determining costs should be the same as the period for recovering costs as to have a recovery period longer than the period for determining costs would result in the marginal costs not being recovered in full from those whose caused them and would be spread amongst other users thus reducing cost reflectivity.

SB returned to discussing the sequencing of reinforcements and questioned how the G3 process dealt with committed schemes that would not be connected for a number years (say 3-5). NB said that such a long timescale for committed schemes was not usual and that the base network for analysis contains only the committed schemes expected to exist in the December of the year for which costs are calculated. G3 believe it would not be correct to include any further committed schemes so as to give the appropriate cost signals for the existing and immediate network.

There was some discussion over how the generation reinforcement costs are calculated. It was confirmed that if a 'typical' generator being connected would not breach the headroom available for generation in a particular network group then no marginal cost would apply. SB suggested that the headroom for each network group should be published to provide signals to generators. G3 responded indicating that publishing headroom data is worth consideration.

Afternoon Session

Consultation Section 5: The G3 Tariff Model

GM and MIL described the G3 Tariff Model by explaining the various aspects of the Excel model.

A question was raised as to whether operating costs included fault costs which many DNOs treat as capital costs. G3 confirmed fault costs are currently treated as operating costs in the modelling.

The method for determining Demand Estimation Coefficients was discussed and whether the half-hourly data streams from settlement was validated in any way. MS confirmed that some validation of the data was undertaken.

A question was raised on how peaking probabilities were determined. GM explained that this was based on network data which determined the percentage of assets with their maximum demand in a particular time period.

SB asked how the Modern Equivalent Asset Value was calculated for the different voltage levels. MIL explained that in the illustrative model it was calculated with the inventory of assets at each voltage level as listed in the Regulatory Reporting Pack with values taken from an industry paper prepared by the ENA in 2002 listing Asset Values for the different type of assets in the network. It was explained that this calculation has the purpose of determining the relative value of the total assets at each voltage in relation to the totality of the network.

AM asked about the split of the yardstick costs and the final tariffs in fixed costs and unit costs. MIL explained that at the moment the split was set up as the costs at the low voltage level plus administrative and billing costs as a fraction of the total costs. GM pointed out that the G3 had not yet decided how to do the split, and that this was one of the reasons why the charges in the consultation paper were published as total charges instead of tariffs. AN stated that it would be helpful to receive comments from users/suppliers on the preferences for this split and what effects the different options could have.

Consultation Section 6: Other Charging Issues

MS gave a presentation on other charging issues raised in the consultation paper. With regard to sole use assets, G3 agreed to provide more clarity on sole use assets in their next update document.

There was discussion on the G3 proposed approach to determining reactive charges. CS commented that Ofgem had consulted on reactive charges last year and the approaches proposed by UU and CN. G3 agreed to review their approach to reactive charges in light of this consultation.

Consultation Section 7: Illustrative Charges

ML outlined the illustrative charges published by G3. It was stressed that this was very much a work in progress document and G3 were continuing to develop and refine their approach and hence further movements in the illustrative prices were likely.

Consultation Section 8: Next Steps

AN outlined the next steps for G3 and thanked everyone for their attendance and contribution to the workshop.

SB thanked G3 for organising the event which he thought was useful in providing a greater understanding of the G3 approach.