Oxera

David Jones
Change Assessment Manager, Change Delivery
Elexon Ltd
4th Floor, 350 Euston Road
London, NW1 3AW

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Dear David

Preliminary response to information request on Zonal transmission losses

As you know, Oxera was commissioned by Elexon in 2006 to conduct a study on the impact of zonal transmission losses (ZTL) applied to the electricity system in Great Britain. The study involved load–flow modelling of the GB transmission networks, alongside modelling of the wholesale electricity market. Oxera undertook the study in conjunction with Professor Janusz Bialek from the University of Edinburgh and Professor Stanislaw Ziemianek from Warsaw University of Technology. The results of the analysis were presented in a July 2006 report entitled 'What are the costs and benefits of zonal loss charging?' and a September 2006 report entitled 'What are the costs and benefits of annual and seasonal scaled zonal loss charging?'

This letter sets out a preliminary response to an information request from Brattle on details of the reports, the methodologies and the underlying assumptions. The response should be considered preliminary given the short time available to respond and the unavailability of some of the relevant staff in the pre-Christmas period.

The questions set out below refer to the July 2006 report, though also generally to the September report. The main difference for the analysis in the September report is that 4*3= 12 snapshots were used per year due to using three snapshots for each season. This should improve the accuracy of the snapshot modelling.

Questions from Brattle are in bold. Responses are given below.

1.On page 7 you write "[t]he total level of demand to be met was reduced by the estimated level of losses, allowing the total net benefit of zonal loss charging to be calculated". We assume that this reduction relates to the impact of zonal losses on demand that you estimate in Chapter 6. Can you confirm this and explain what you did?

The key to understanding this is the description of load flow packages used on page 6. The so-called DC load flow program, which was used to estimate the TLFs as required by the Modifications, is lossless (i.e. network resistances are neglected). The actual level of variable losses due to a particular despatch pattern had to be evaluated using so-called AC load flow which contains resistances and in which total losses are calculated as the difference between generation and demand. As the input data to a load flow program are individual nodal demands and generations, the nodal demands had to be scaled proportionally down by the estimated level of variable losses and the AC program was run to calculate the actual variable losses. The procedure was

Oxera
Park Central
40/41 Park End Street
Oxford OX1 1JD
United Kingdom

Tel: +44 (0) 1865 253 000
Fax: +44 (0) 1865 251 172

enquiries@oxera.com
www.oxera.com

Oxera Consulting Ltd
Registered office at Park Central 40/41 Park
End Street, Oxford OX1 1JD
Registered in England No. 2589629
VAT Registration No. 768 4006 16

repeated until the error (i.e. the difference between the assumed and the actual level of losses) was acceptably small. This is a standard trick in load flow studies in order to avoid the “chicken and egg” situation: you cannot run a load flow without specifying generation and demand in each node but you cannot do it as you do not know losses without running the load flow.

2.On page 8 you say that "data ... was taken from the 2005 Seven Year Statement and scaled proportionally to correspond to the three loading snapshots". Can you explain what you mean by "scaled proportionally"?

SYS data contains peak demand figures for GSP transformers so they had to be scaled down to correspond to the loading periods modelled.

3.On page 9 you say that differences between your and PTI TLFs of 0.005 and 0.009 are acceptable. How did you decide whether a difference was acceptable or not? What criteria did you use?

The assessment was based on our judgement taking into account the level of differences and the assessed explanations for them, as discussed in the following paragraph in the report.

4.On page 9, you show a comparison between the PTI TLFs and the TLFs from the load-flow model based on the despatch from your economic model and this is used as validation of the economic model. Did you perform any other type of validation of your economic model such as whether the model produces reliable simulations of prices or generation despatch across the year?

Yes, validation was done comparing the results of the simulation for 2005/6 to actual outputs for 2005/6 in addition to the TLF comparisons. Other validation exercises have been undertaken for the Oxera wholesale modelling during its use in other contexts.

5.On page 9 you explain that difference between your TLF and the PTI TLF in zone 10 is due to different load factors being used for Aberthaw. When you undertook the more detailed economic modelling what load factor did you find for Aberthaw i.e. did you find it ran at baseload, as in your snapshots, or at mid-merit, as in the Elexon data? Did you confirm that adjusting Aberthaw's load factor resulted in a TLF for zone 10 that was similar to the PTI one? Did Aberthaw continue to operate at baseload in the snapshot periods throughout the period studied?

The economic modelling over the year (including the emissions constraints) did show Aberthaw running as mid-merit, though its load factor under the assumed fuel prices increased from 2008 as opted-out stations had their output restricted.

6.How did you incorporate the effects of plant maintenance into your snapshot modelling, particularly for the seasonal analysis?

The Oxera wholesale model profiled plant outages for maintenance across months. However, the approach used for the snapshot analysis was similar to that used for the 2003 DTI analysis as summarised in the report as follows:

‘In carrying out the modelling, it was necessary to make some assumptions about the availability of plant for the three levels of snapshot demand that were modelled. OXERA assumed that a high proportion of plant would be available for generation during peak periods. For the off-peak and trough periods, two modelling options were considered: taking individual plant off-line; or scaling back the capacity of all plants of a given type to reflect overall availability. With regard to the first approach, OXERA concluded that the assumption as to which individual plant might be off-line during a particular demand period was too discretionary, and that the assumption might have a significant impact on flows. Therefore, OXERA adopted the second option, while recognising that, in practice, this pattern of plant availability is unlikely.’ (see Oxera’s 2003 DTI report: ‘The impact of average zonal transmission losses applied throughout Great Britain’, page 83).

7.On page 9 you say the differences in PTI and Oxera TLFs for the Scottish zones during the summer are "a function of the assumed loadings during a time when net electricity flows in these zones are sensitive to actual loading at the time". Can you explain this in more detail?

The Modifications stipulated using the intact network model, i.e. assuming all transmission lines in service, and this was the assumption used in our modelling. In fact in summer some transmission lines are taken off-service for maintenance which may cause transmission constraints and forced off-merit generation – see NGET report on constraints at:

http://www.nationalgrid.com/NR/rdonlyres/F62370C0-1865-4FB3-8B06-AB6CE4DFFD77/16952/GBSQSSEconomicGuidance.ppt

The quoted NGET report says that export constraints in Scotland arise in summer due to summer transmission outages (for maintenance). We believe that this was the main reason for the summer differences between PTI and Oxera modelling results. PTI used the actual despatch data which included forced off-merit despatch to relieve actual transmission constraints while our modelling was based on the intact network model and hence did not show any summer constraints. Consequently we have used unmodified optimal despatch. Generally our simulations showed that TLFs in the Scottish zones, and especially in zone 14, were very sensitive to dispatch patterns. Hence any off-merit despatch affecting power flows in Scotland must have caused significant variations in TLFs. PTI results for summer show an unusual shift of TLFs in zone 14, presumably due to the constraints, which was not replicated in our simulations as we could not see any constraints due to using the intact network model.

8.In the load flow modelling for future years, what assumptions did you incorporate regarding changes to the network?

Changes to the network were made in accordance with those already announced in the SYS. The network configuration was the same in the uniform and zonal cases (ie, it was exogenous to the analysis).

9.On page 11 you describe how you modelled the growth in renewable generation. Could you provide us with a table showing the amount of wind (both offshore and onshore) added in each year and the zones in which these wind plants were added?

This will be provided separately.

10.On page 12 you state that "plant that have opted out of the [LCPD] Directive will be limited to 20,000

hours of generation between 2008 and 2015". How did you apply this limit in your model? Did you assume the same limit on generation in each year or something different?

The Oxera model in general optimised generation patterns for opted-out plant over the whole period 2008 to 2015, but this can only be applied when running multiple years at once. In the year-by-year analysis undertaken for the Elexon analysis annual limits were applied. This was consistent with DTI modelling at the time.

11.On page 13 you state that "[a]ll other plant closure decisions were based on market outcomes under the different scenarios". What criteria did you use for deciding whether non-nuclear plants should be closed? Which plants did you assume close under each scenario and when? Were the closures different between the uniform and zonal analyses?

Closures were based on the ability of the stations to cover operating costs over a period of time. No explicit mothballing decision was incorporated. There was some discretion used in circumstances where a station was only making small losses for one year or consistently making small losses (given some of the plant would have had balancing and reserve contracts that would have supported them for some of the shortfall).

Details of the individual station closures will be provided.

12.On page 13 you show two new generic CCGT plants coining on line in zones 2 and 7 with capacities of 1,000MW and 2,000MW. Why did you choose these zones and plant sizes?

The zones were chosen because it was considered that these areas would be most advantageous for new entry other things being equal. Issues such as the availability of sites, proximity to pipelines, TNUoS charges were considered. The capacity that enters in any give year is determined by the modelling results - if prices are high enough and stay high enough after entry then capacity is added.

13.On page 30 you say that "[z]onal results were subtracted from uniform results to obtain differences between the charging regimes" but do you mean the other way round as Tables 3.8 to 3,11 suggest that uniform results were subtracted from zonal results? For example, the output in Scotland is shown decreasing in the tables, which would seem more likely to be an outcome of moving from uniform to zonal losses.

This is correct.

14.On page 38 you explain how you have used method 2 to estimate the value of loss savings. Did you test how different the savings would have been if you had used method 1?

A more detailed comparison of the differences between Methods 1 and 2 is presented in the 2003 DTI report (pages 26 and 27). As discussed in the July 26 report it was concluded that Method 2 was preferable though both methods have advantages and disadvantages as discussed.

The concern with Method 1 is that marginal TLFs are valid only at the margin so multiplying them by generation at a node gives an overestimate. On the other hand using 3 snapshots per year for the second method amounts to linear averaging which may lead to a slight underestimation of the actual annual losses. Losses are approximately proportional to squared power flows so using an averaged power flow underestimates the losses. This error was smaller for modification P204 as when using the seasonal approach, 4*3 = 12 snapshots were used per year (3 snapshots for each season).

15.On pages 45-46 you describe the minimal impact of zonal transmission losses on interconnectors linking the Great Britain with other markets. Could you explain how you modelled the development of flows across the French and Dutch interconnectors?

The French interconnector was modelled effectively as a generator, though it had different availability profiles to capture the shape of imports and exports. The proposed Netherlands link was not modelled as constructed given its pending approval status in 2006.

16.In Tables 5.5 and 5.6 you provide your analysis of the influence of TNUoS and NTS exit charges on locational decisions. It does not appear that you have taken any account of future changes in these charges, is this correct?

This is correct – possible future changes in transmission charging levels or methodologies were not forecast.

17.Tables 5.5 and 5.6 on page 51show the difference excl. and incl. Scotland. Can you explain what you mean by "Difference"?

These tables were designed to give an idea of the ranges of these regional elements. Since Scotland was the outlier the table simply showed the ranges for these elements with and without Scotland included.

18.On page 59, the values quoted above Table 6.2 do not appear to correspond with those in the table, are these simply typos? For example, you state the "[t]he Midlands shows the strongest signs of this behaviour, with an £18,000 reduction in benefits" but the table shows £16,000.

The text refers to all of the tables 6.2 to 6.5, not merely to Table 6.2. The maximum loss reduction referred to is seen in Table 6.5 while the £18,000 Midlands figure is seen in Table 6.4.

19.On page 67 you show the results of NPV calculations of future benefits. Could you provide us with the data used in these calculations?

This data will be provided separately. As with the 2003 DTI analysis (see pages 77 and 78 of the 2003 report) the estimated benefits were calculated in the following way:

– The annual results for the modelled period were used to give an estimate of the average value of generation redespatch per year resulting from the change. The NPV of this average annual benefit was then calculated over the two illustrative periods: to 2015/16 and to 2020/21.

– This was combined with the estimated average annual demand response benefits and operating costs.

– The one-off implementation costs were deducted.

An alternative approach would have been simply to discount each year's generation redespatch benefit individually for the estimated NPV to 2015/16 (which would have given slightly different figures – in some cases slightly higher and in some cases slightly lower), although this method could not have been used to estimate the NPV to 2020/21 since annual analysis was not conducted beyond 2015/16.

I hope that this addresses the queries raised. The additional data referred to will be sent separately.

Yours sincerely

Martin Brough
Director