Response: Competition and Markets Authority Energy Markets Investigation

April 2016

RenewableUK is the leading trade association in the renewable electricity sector, representing over 450 organisations across the value chain in the wind, wave and tidal stream industries. As our members are focused on the supply side of the power sector, we limit our comments to the remedies proposed for the wholesale market for power.

Allocation of Contracts for Difference

As set out in our response to the initial consultation on recommended remedies, RenewableUK supports the proposals around CfD allocation that the CMA has put forward. These proposals will promote transparency in the decisions made around how technologies move through the CfD system, though we would argue that in addition DECC needs to set out clearly the principles that it will apply in guiding that journey. Developers attempting to navigate projects through the system will benefit from the enhanced visibility and clarity that rigorous impact assessments of negotiated contracts and the management of allocation Pots should bring.

We have a few comments to make on the specific proposals on the impact assessments. In particular, we have concerns around Government's ability to remove technologies from CfD allocation through executive action. One instance of this would be if Government decided that an emerging technology will not benefit from negotiated CfDs or preferential access to CfDs through a minimum or Pot 2. Such a decision would presumably be made on the basis that the technology in question can demonstrably be shown to be failing to make sufficient progress towards cost convergence and cannot be reasonably expected to do so in the future. This needs to be very clearly demonstrated in the relevant impact assessment, since withdrawal of access to CfDs will mean denial of access to the market overall. The consequent standard of proof would therefore have to be higher than for actions such as moving a technology from Pot 2 to Pot 1.

Of equal concern is the ability to remove technologies from the 'Established' Pot 1. As we argued in our submission to the initial consultation on recommended remedies, to remove a technology from CfD allocation is effectively to deny it access to the market, since the wholesale price alone cannot currently, and in our view will not in the future, support investment in new generating capacity, particularly for capital-intensive renewables. Access to the CfD mechanism also enables low-cost finance to be obtained, due to the revenue certainty and private contract form of the instrument.

Consequently, we fail to see how removal of any technology from the technology-neutral Pot could result in benefit for consumers. If the technology being removed is competitive with the other technologies in the Pot, then the result is that the benefit of that technology is lost to the consumer. Competitive tension will be reduced and strike prices will therefore be higher than they would otherwise have been. If the technology is not competitive, then it will not win contracts and its removal from the allocation is pointless.

We would therefore argue that if DECC is proposing to remove any technology from CfD allocation, from any point in the allocation process, then the relevant impact assessment should include a

comprehensive evaluation of that technology, showing to a high standard of proof that its removal would be a net benefit to both current and future consumers, and the wider economy. In addition, we would recommend that no low-carbon technology should be excluded from the ultimate technology-neutral bidding Pot, as to do so can only result in a detriment to consumers.

Finally, while we agree that having visibility on the allocation of technologies to Pots and the budget available to these Pots a year in advance is beneficial, we have some concerns about the loss of flexibility involved if the budget is fixed this far in advance. In particular, we would like Government to retain some discretion to *increase* the budget available for a round less than a year in advance, but not to decrease it. This is particularly important in order to protect the 'buying power' of the budget set out should projections of the wholesale price decrease between the budget being set and the round itself. If the point of setting budgets in advance is to give developers confidence in the 'market' for their projects, the size of the procurement should be protected.

The experience from the first CfD allocation round is instructive here. An indicative budget of £205m was set in July 2014 (£50m for Pot 1 and £155m for Pot 2). The final budget notice increased the budget to £300m (£65m for Pot 1 and £235m for Pot 2), but just before then DECC had released revised wholesale prices that saw reductions in the forecast numbers. While the additional budget for Pot 2 still led to a larger amount of capacity than would have been possible with the original budget, the additional £15m for Pot 1 was entirely offset by the decreased wholesale prices and no more capacity could come forward than was expected with the original budget and wholesale price forecasts. If there had been no flexibility to increase the budget available, there would have been a reduction in the buying power of the budget and a blow to confidence of the developers seeking CfDs in that round.

Locational Adjustments for Transmission Losses

Regarding *Locational Adjustments for Transmission Losses*, the CMA has proposed the following pair of remedies:

- National Grid is to both calculate and charge for transmission losses on a locational basis; and
- The CMA will require that 100% of the costs of transmission losses are borne by generators.

RenewableUK strongly objects to both of these proposals. We hold the view that any implementation of a new method to allocate the costs of Transmission Losses should be sought through a BSC Modification, through the proper industry channels, allowing full transparency on the decisions and reasoning behind the modifications.

The loss of energy through the transmission network in the financial year 2014/15 has been calculated to be 1.84%[1] of total generated electrical energy (5.68TWh). Currently, the allocation of the costs of transmission losses are dealt with under Section T of the BSC. They are allocated in the proportions of 45% to generators and 55% to demand, and allocated to all parties on the basis of their metered energy volumes.

BSC Section T Paragraph 2.2.1 sets the 'delivering' trading unit allocation to a factor of 0.45, with the remaining 0.55 portion allocated to 'offtaking' trading units, and it also indicates that the Transmission Loss Factor is set at zero. This is the component of the Transmission Loss Multiplier calculation which would allocate losses on a locational basis. The CMA's proposals would require both of these values to be changed, which would impact on how the Transmission Loss Multiplier is applied throughout the BSC, and indeed beyond. Elexon's own guidance document[2] on Transmission Losses states that "…a [BSC] Modification would need to be raised to change the TLF values." Any changes would have to be considered with great care, and all implications examined.

We note that the CMA report cites the previous BSC Modifications raised to tackle the issue of the non-locational nature of the allocation of transmission losses. Four BSC Modifications have been

[1] http://www2.nationalgrid.com/UK/Industry-information/Electricity-system-operator-incentives/transmission-losses/
[2] https://www.elexon.co.uk/wp-content/uploads/2013/11/transmission_losses_v4.0_cgi.pdf

raised to tackle the issue of the non-locational nature of the allocation of transmission losses: P198 (Dec 2005); P203 (Jun 2006); P204 (Jul 2006); P229 (Nov 2008). All four of these BSC Modifications were rejected by the Authority: the most recent, P229[3], was rejected in September 2011[4]. We do not agree with the CMA that no resolution to this issue has been reached through the normal code modification process because of producers acting out of commercial interest to prevent change, and we find that there is insufficient justification either for this claim or to say that a future modification process would therefore be effective. In Ofgem's decision on P229, they were ultimately not convinced either that the measures would operate in the interests of existing and future consumers, or that the approval of the measures would be in line with best regulatory practices. They were concerned with the large distributive impact which would follow from approval of the measures, in particular "in the context of the relatively modest scale and uncertainty of the expected efficiency benefits". Ofgem points out that the wholesale price of electricity is "driven by the marginal cost of price-setting plant, rather than the generality of cost". Considering the more than doubling of capacity of renewables on the system since this decision in 2011, it is worth considering in detail the changes to the short run marginal cost of electricity from 2011 to today – where we have far greater volumes of wind now in the lower strata of the Merit Order – and whether analysis which Ofgem considered demonstrated insufficient net efficiency benefits in 2011 would, if re-run today, prove greater or lesser net efficiency benefits to consumers.

In these provisional results, it is stated that the concerns that led Ofgem to reject the modification do not outweigh the long-term economic benefit – namely, the large distributional impact between individual generators and between suppliers/customers – and the uncertainty of the intervention's efficacy given the changing regulatory environment. RenewableUK does not consider that the CMA has provided significant evidence to support its view that these concerns are now immaterial. Recommending a revised version of the P229 modification is not sufficient detail to understand the distributional impact, and we reflect many of our members' concerns that insufficient information has been provided in Appendix 2.2 to model the effect, even for their own businesses. Moreover, the changing regulatory environment comprises significantly more than the Capacity Allocation and Congestion Management regulation cited in these provisional results and encompasses, most importantly, ongoing work by both National Grid and Ofgem on wider TNUoS charging issues.

We also note that a locational transmission loss charge would explicitly fall outside of the €2.50/MWh transmission charging cap set by EU Commission Regulation No 838/2010 Part B[5]. Three CUSC modification proposals have been made to deal with this cap (CMP224, CMP251, & CMP261) and we urge the CMA to consider the detailed work undertaken by the industry through these modifications when considering the implication of a new locational charge.

As noted in the CMA report, it has been submitted to the CMA that the proposed remedy would confer an advantage to interconnected continental European generators, who, whilst supplying 6.18% of the UK's electricity in 2015[6], are neither liable for transmission losses, nor for TNUoS charges. Our calculations on any augmentation to the Transmission Loss Multiplier values for the financial year 2014/15 suggest that not only will GB generators cover 100% of the cost of transmission losses, but that they will also cross-subsidise losses due to power delivered via Interconnectors. We do not agree with the CMA that this clear commercial advantage is immaterial to the consideration of the best approach to creating a more efficient allocation of transmission losses within GB and nor do we agree that the theoretical work and modelling undertaken is sufficient to state this with any degree of certainty.

Even if sufficient detail had been provided, the results of the modelling for these provisional results explicitly state that with respect to its impact on customer bills and generator margins "the modelling results are likely to be highly uncertain". Furthermore, that the dynamic effect was explicitly not considered within the model because it was deemed to overcomplicate the modelling significantly undermines the model's ability to predict with accuracy both the distributional impact and the long-term benefit to consumers that are the core arguments used to justify this change. This is

[3] These documents cover the details of P229: https://www.elexon.co.uk/mod-proposal/p229-introduction-of-a-seasonal-zonal-transmission-losses-scheme/
[4] The letter from Ofgem rejecting P229: https://www.ofgem.gov.uk/sites/default/files/docs/2011/09/p229-d_0.pdf
[5] https://www.energy-community.org/portal/page/portal/ENC_HOME/DOCS/2930027/0633975AD7687B9CE053C92FA8C06338.PDF
[6] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/511955/Energy_Trends_March_2016.pdf

notwithstanding our members' concern with the detailed modelling used to estimate the short-run cost-benefit analysis.

We also note that there is little detail within the modelling on the interaction between the substantial locational price signal within the existing TNUoS charge[7], which is often the largest cost line item for a generator, and additional locational pricing – beyond stating that "TNUoS prices [are] the main driver of locational investment decisions". In the first place, further detail should be explicitly stated in order to allow the industry to understand the potential impact. Secondly and more fundamentally, the locational pricing element of the TNUoS charge already provides a strong economic signal to developers as to the costs of tapping into the best of the UK's natural power resources. The report states that in relation to decisions as to where to site future generators, "cost differences due to locational losses are small compared to the cost differences due to locational TNUoS charges and other locational charges", and makes it clear that the application of zonal charges in the model has no impact on optimal generation investments. We do not agree with implementing another locational element to system charges on top of the current measures.

Moreover, the results of even this limited modelling in terms of reductions in bills do not seem to support the confidence with which the CMA proposes that locational pricing should come into effect through an order on National Grid by late 2017. We note particularly the increases in consumer bills in the model's "High Case" (a view on merit order scenarios, and fuel and carbon prices) and the considerable variation across the three scenarios – where the reductions range from £278m to more than five times this at £1.6bn. Given the limitations of this modelling, such a large range – and a clear scenario where the effect on consumers is negative – does not seem to support a non-consultative approach.

2015, £ million

	Reference case		*High*		*Low case*	
	A	*B*	*A*	*B*	*A*	*B*
Total aggregate change in customer bills	1,560.63	1,637.78	–200.81	–214.53	38.26	278.80
Change in generator margin	–897.87	–705.89	312.55	660.80	337.57	719.50

The report states that the driver in the model for thermal investment in the South is "in response to TNUoS signals", which is predicted to lead ultimately to an overall increase in wholesale prices. Using the results from Table 2.4, below, it can be seen that the reference case is the only scenario to have only reductions in bills and that in the High Case, all regions have higher bills except North Scotland and, similarly, half of regions have higher bills under the Low Case. Furthermore, the total range from locational pricing of -£0.94 to £2.57 per customer per year (NPV) do not seem sufficient to overcome, as these findings also explicitly state, their sensitivity to the uncertainties of the wholesale price.

£

Change in annual customer bill	*Reference case*		*High case*		*Low case*	
	A	*B*	*A*	*B*	*A*	*B*
National average	1.69	1.77	–0.22	–0.23	0.04	0.30
North Scotland	2.57	2.66	0.77	0.75	1.08	1.34
South Scotland	1.69	1.77	–0.22	–0.23	0.04	0.30
North England/Wales	0.43	0.51	–1.27	–1.29	–1.12	–0.86
Midlands of England/Wales	1.02	1.10	–0.51	–0.53	–0.39	–0.13
South England/Wales	0.70	0.79	–0.94	–0.96	–0.80	–0.54

Finally, there is no consideration within the findings of the CMA's proposals' impacts upon current Contracts for Difference (CfD) contracts and their underlying value calculation mechanism. CfD

[7] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

strike prices are adjusted based on the evolving Transmission Loss Multiplier (TLM) values. We note that the usage of the TLM within the CfD strike price adjustment calculation is an opaque process. The usage of the TLM values to calculate a 'TLM Charge' is wholly unclear, and this presents a problem when attempting to analyse the impact on the CfD of amending transmission loss charges. With potentially higher strike prices for CfD projects, the number of projects able to obtain support will be decreased. We urge the CMA to consider more broadly the impacts of these proposals, and to consider the breadth and depth of the impacts.

Thus, we object to the proposals on several grounds, notably:

- There have been several attempts, outlined above, to implement locational transmission loss charging in the Balancing and Settlements Code (BSC), all of which have failed. We believe that an order on National Grid is not the correct way to impose such a change. A Modification Proposal should be submitted to the BSC Panel for proper consideration, as this change would require at least two material changes to the BSC.
- There is already a strong locational element in the Transmission Network Use of System (TNUoS) charge which is faced by transmission connected generation in Great Britain.
- Transmission losses account for a small proportion of the energy generated, and they are a natural consequence of having a national transmission network.
- We should be encouraging the best renewable technologies to be sited where the best resources can be found. Locational losses will add yet another layer of complexity to an already very complex charging system.
- As this locational charge would not be applied to electricity delivered via interconnectors, the proposals put GB generators at a competitive disadvantage in relation to European suppliers, and this effect cannot be considered immaterial without further, more in-depth analysis.

For further information please contact:

Gordon Edge
RenewableUK Director of Policy