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By email: EMR_CMRules@ofgem.gov.uk

27 May 2016

Dear Philippa,

Statutory consultation on changes to the Capacity Market Rules (the "Rules") pursuant to Regulation 79 of the Capacity Market Regulations 2014 (the "Regulations")

We would like to take this opportunity to provide our response to Ofgem's Capacity Market (CM) Rules consultation. We welcome Ofgem's focus on simplifying CM auction prequalification requirements and providing flexibility to DSR.

Our responses to the specific questions on change proposals and capacity calculation proposal are outlined below.

Kind regards,

Polina Kharchenko
Regulation

Questions on proposals

Q1. CP136 (interconnector capacity): Do you agree that de-rating from CEC rather than TEC is a more appropriate way to measure the De-rated Capacity of Interconnector CMUs? Do you agree with the suggestion to cap Interconnector de-rated capacity at TEC, or should the requirement for interconnectors to hold sufficient TEC be removed altogether?

Ofgem's suggestion to de-rate Interconnector CMUs from CEC and include a provision for any long-term technical issues in a de-rating factor for Interconnector CMUs sounds sensible. This approach would reflect the maximum potential output Interconnector CMUs can deliver during a stress event.

We also support the proposal that de-rated capacity of Interconnectors CMUs should be capped at TEC as this ensures that Interconnector CMUs meet prequalification requirements related to connection arrangements which are in place for all capacity providers.

Separately, the notion of Interconnector CMUs not holding TEC would be relevant if they were purely deemed as transmission assets. This is clearly not the case in the Capacity Market whereby they are treated equivalent to Generating CMUs. Therefore we do not believe that the requirement for interconnectors to hold sufficient TEC should be removed.

We also note Ofgem's decision to only partially take forward CP131 raised by the Electricity Settlement Company. Ofgem is minded not to amend the Rules so that an Interconnector CMU's output and capacity obligation is measured using metered output rather than the Interconnector Scheduled Transfer (IST). For other types of CMU the output is an actual metered volume but for an Interconnector CMU it is a scheduled value as given in Rule 8.6.2.

We appreciate that the IST is the notion defined in the Balancing and Settlements Code for Interconnector BMUs. However, taking into account that interconnection is treated in the same way as generation in the Capacity Market; the same metering arrangements should apply.

Q2. CP129 (adding DSR components): Do you agree there are overall benefits to creating a bespoke process for adding new DSR CMU components? (Please provide evidence to support your answer)

We support Ofgem's minded-to decision to amend Rule 8.3.4(a) so that Capacity Providers are able to replace DSR CMU Components in a capacity committed DSR CMU to improve reliability of the DSR portfolio. We believe that the current testing requirements should ensure that the overall quality of the DSR portfolios remains robust despite newly granted ability to add new components at any time without needing to prequalify a new DSR CMU.

Separately, we support an amendment to Rule 8.3.4 (d) (CP130) which would specify that a DSR CMU Component that has been removed from a DSR CMU cannot be reinstated in the same Delivery Year. We do not believe it is necessary to remove Rule 8.3.4(d) altogether.

We also support CP124 which would allow the performance of portfolios of CMUs to be assessed on an aggregate basis during DSR Tests and Satisfactory Performance Days. We provide further details on this in our response to Question 6 (Portfolio Testing).

Q3. CP95 (reallocating DSR components): Do you agree that the combination of CP124, CP129 and CP130 would be a better solution to the issues that CP95 seeks to address?

We agree with Ofgem that that the combination of CP124, CP129 and CP130 provides sufficient flexibility to DSR and is a better solution than the one suggested by CP95. Therefore CP95 should be rejected.

Q4. CP108 (CM warnings): Do you think there is a need to align Capacity Market Warnings with other existing system warnings? If so, how would you suggest this is done? Are there any associated risks?

Currently the System Operator can issue a range of National Electricity Transmission System Warnings, as defined in the Grid Code, to alert the market to specific anticipated system conditions. Those include Inadequate System Margin, High Risk of Demand Reduction (HRDR) and Demand Control Imminent (DCI).

Separately, Rule 8.4.6(a) suggests the System Operator must publish a Capacity Market Warning in accordance with Rule 8.4.6(b) at times when either: (1) the System Operator gives a Demand Reduction Instruction to one or more Distribution Network Operators; (2) an Inadequate System Margin is anticipated to be 500MW in any settlement period falling at least 4 hours after the expiry of the current Settlement Period, or (3) an Automatic Low Frequency Demand Disconnection takes place. The System Operator will issue a 'Capacity Market warning' at least 4 hours in advance of any anticipated stress event.

We believe that the triggers for all system warnings and gradations of these warnings should be clearly outlined so that the market can interpret such warnings correctly. Currently, it is not clear how a four hour notice period would interact with a CM Warning issued in relation to a Demand Reduction Instruction or Automatic Low Frequency Demand Disconnection. At the same time, we would like to make it clear that if alignment of all system warnings is being pursued, any proposals in relation to a CM Warning should not deviate from the agreement that has been secured through the Capacity Market auction. Specifically, a four-hour notice period should remain in place.

Separately, Rule 8.4.6(b) suggests that a CM Warning must be published by the System Operator on the website specified by the System Operator. We would support the proposal to publish such information on a separate ‘CM warnings’ dedicated website as this would allow non-BM participants to access such information.

Finally, we would like to emphasise that all three triggers of the CM Warning should be consistently made known to the market. For example, this has not been the case in the past in relation to such system stress notices as the HRDR and DCI.

Q5. CP128 (LFCO formula): Do you agree that the LFCO formula will not scale delivery obligations appropriately during the first TA Delivery Year? Is this issue significant enough to require changes before first TA Delivery Year (starting in October 2016)? If so, how should the formula be amended?

Taking into account that Ofgem agrees that the LFCO formula will not scale delivery obligations appropriately during the first TA Delivery Year, we believe this issue should be revisited and rectified by Ofgem before October 2016.

Q6. CP115 (volume reallocation): Do you agree there is an issue with Rule 10.4.1 (c)(ii)? If so, would our suggested addition to this Rule fix the problem? If not, how should it be amended?

We support the view that the wording of Rule 10.4.1 could be clearer. We also agree with the argument outlined in CP115 that Rule 10.4.1 does not explicitly state that restrictions apply to each individual trade between two CMUs rather than the net aggregate traded volume. It does not seem that a reference to the Aggregate Traded Capacity Market Volume in Rule 10.4.2 is sufficient to draw this conclusion.

In addition, while Ofgem’s clarification on Transferees’ restrictions is welcome, it is difficult to deduce from the actual wording of Rules 10.4.1 (b) and 10.4.1(c) that those apply to the outturn volumes following a trade between two CMUs - not just to the Transferor’s volume. We would suggest that this is explicitly stated in the Rules, for example by inserting a Rule with a specific focus on Transferees’ restrictions mirroring Transferors’ restrictions.

Separately, a potential clarification suggested by Ofgem in reference to Rule 10.4.1(c)(ii) seems to remove the relevance of this obligation for the Transferor. This would also be the case if Rule 10.4.1(b)(ii) was adjusted in a similar way.

Q7. CP124 (portfolio testing): Do you agree with our assessment of the benefits and risks with CP124?

We support CP124 which would allow the performance of portfolios of CMUs to be assessed on an aggregate basis during DSR Tests and Satisfactory Performance Days. We would suggest that the benefits of this proposal are very well articulated by Energy UK in their submission. Importantly, this change would allow aggregators to compete more effectively in the CM which would lead to more efficient auction outcomes and ultimately a better value for consumers. A potential risk to CP124 being implemented is that increased flexibility provided to DSR aggregators could result in a decreased efficiency and quality of DSR portfolios. However, we believe that a combination of CP124, CP129 and CP130 means that reliability of DSR would increase overall.

Q8. CP98 and CP148 (Firm Frequency Response): Do you agree with the solution put forward in these proposals to ensure the participation of dynamic FFR in the CM? If not, what changes to the DSR test and volume calculation are necessary to achieve this?

We support Ofgem's view that the proposed addition to Rule 13.2.6 (a) so that "Non-zero Contracted Output can be calculated for each DSR CMU Component of the DSR CMU to show a positive DSR volume" has an inherent risk of rewarding providers for increasing demand during a stress event. We therefore believe that Ofgem's proposal to consider only reductions in demand ("positive DSR volume") in the 'Adjusted Load Following Capacity Obligation' formula is a sensible solution to ensure the participation of dynamic FFR (or other dynamic services) in the CM while guaranteeing efficient allocation of CM payments.

Separately, we support Ofgem's decision to reject CP118 which would introduce a specification of Firm Frequency Response service. In line with Ofgem, we believe this would create ambiguity over the status of other existing and/or future subsidiary schemes which are also not explicitly set out in the CM Rules.

<u>Questions on connection capacity</u>

Q9. Do you agree with our analysis and conclusions in relation to connection capacity?

We disagree with the assertion that "parties should not have an incentive to choose a MEL which is lower than their maximum capacity" as there are legitimate and prudent operational reasons for a generator to do so.

While it may be the intention of the current CMU design that parties should provide headroom above their de-rated capacity obligation, it is not currently a requirement. The means proposed (testing up to connection capacity, penalties for failure to meet connection capacity) may well be onerous enough to see generators offer lower levels of capacity into the auction as mitigation against the risk of losing all capacity payments should output fall marginally short during proving.

For example, a 100MW generator with a 10% derating factor that may previously have entered 90MW into the auction may now decide to "withhold" 5MW for risk mitigation, entering a de-rated capacity of 85.5MW. If repeated over a significant number of other bidders this may notably reduce the amount of capacity available in the auction.

We do agree with Ofgem’s preference to allow generators a free choice of connection capacity (CEC, TEC or historic output). However, we consider that testing to the full connection capacity, with associated penalties, is likely to result in generators committing less capacity into the auction as a form of risk mitigation.

Q10. Would the satisfactory performance requirements remain appropriate if we test up to connection capacity? In particular, would it be appropriate to demonstrate satisfactory performance on three separate days, and for CMUs to lose all capacity payments if this is not met?

We require further clarity on the proposed testing and penalty regime. In principle it remains reasonable to ask generators to demonstrate satisfactory performance on three separate days, however the prospect of losing all capacity payments if this is not achieved is likely to encourage generators to reduce the level of capacity they commit in the auction.

An alternative option could be to require demonstration of satisfactory performance at the connection capacity but restrict the penalty to the shortfall in MW between the connection capacity and observed performance, with the generator losing capacity payments to this on that basis.

It is unfair to overly-penalise generators who have entered a connection capacity in good faith that they believed they could achieve at the time of the auction, but subsequently (three to four years later) can not demonstrate, particularly when they can still meet their de-rated obligation.

If the provision of headroom above de-rated capacity is an expectation of the Capacity Mechanism, and is to be the basis of the performance requirements and penalty regime, then this should be firmly reflected in the design of the mechanism and the auction itself. If generators are expected to deliver their full capacity, as opposed to de-rated capacity, then this should be the basis upon which the auction should be cleared and contracts issued. The target contracted volume should be adjusted to reflect any additional “insurance capacity” desired to meet security of supply objectives.

Q11. Would market rules around exceeding TEC result in genuine capacity being excluded under this approach? Does the ability to purchase short term TEC help address this? If not, is this a significant enough issue for concern?

It may be the case for some generators located in high TNUoS cost zones that genuine capacity above TEC could be excluded because the generator has made a commercial decision that the cost of procuring additional TEC exceeds its commercial value. The ability to purchase short-term TEC may help address this, though issues remain; the cost of this additional TEC can be prohibitive while the process and timescale to acquire short-term TEC may be a barrier to utilising the product effectively. These issues are beyond the scope of this consultation.

Under the terms of Maxgen contracts generators are allowed to exceed their TEC, thus provided that the unit is capable and holds a Maxgen contract then the unit could be expected during CM stress events to export beyond their TEC on a best endeavours basis.

Q12. Do you consider that there is a significant risk of capacity withholding if generators are given a free choice of connection capacity? Would any additional measures be needed to help mitigate this risk (e.g. minimum capacity thresholds or supporting justifications for going below certain thresholds)?

We do not believe that free choice of connection capacity would in itself result in the withholding of capacity as there would be no incentive for generators to forego CM revenues.

We do, however, believe there is the potential risk of less capacity being entered into auctions if a penalty structure is introduced that requires generators to meet full connection capacity under test conditions or otherwise lose their capacity payments. The risks associated with this may cause some participants to decide that the loss of revenue from accepting a capacity contract on a lower volume is an acceptable “risk premium” to pay.

In addition, the capacity market is a voluntary arrangement where a generator commits to provide a specific level of capacity which it gets paid for. Therefore, if Ofgem decides to set minimum capacity thresholds, clear justifications for such a market intervention should be provided.