Five Year Review of the Capacity Market Rules

Ofgem consultation

Background to ENGIE

In the UK, ENGIE employs 17,000 people in a number of activities across the energy value chain, as well as through its extensive services and regeneration businesses.

In generation, ENGIE owns First Hydro in a 75/25 joint venture with Brookfield Renewable Partners. With a total capacity of 2088MW, it is the UK's largest pumped storage operator. ENGIE has committed £50m to the refurbishment of two units at its Ffestiniog pumped storage power station on the basis of 15-year Capacity Market refurbishment agreements awarded in the 2016 auction.

ENGIE also has a 50% stake in over 80MW of renewable generation and a 23% stake in he Moray East offshore wind project which secured a CfD FiT for 950MW in the 2017 auction . In supply, ENGIE operates an Industrial and Commercial (I&C) and Small and Medium Enterprise (SME) B2B electricity and gas supply business, and a domestic electricity and gas retail offer through its Home Energy business.

It owns the country's largest district heating business, providing district energy solutions to the public, commercial, industrial and residential sectors. A key site is the Olympic Park District Heating facility in London. Following the acquisitions of Balfour Beatty Workplace, Lend Lease FM and the Keepmoat regeneration business, it is also one of the top five service companies in the UK.

General comments

- **Interactions between the energy, capacity and balancing services markets are inevitable. Each market should be coherent in its own right. Where market design has incentivised inefficient outcomes, it is right that the design is corrected - it is not necessary to delay making changes in order to address these markets all at once.**

- **ENGIE views the Capacity Market rule change process as working reasonably well and fears that adding in the CMAG will introduce delays to making changes.**

- **At 8 weeks long, the current pre-qualification window is appropriate. What must be avoided is pushing auctions back even further - any more shortening of the current delivery lead time to accommodate longer pre-qualification could impact on new build timescales.**

- **Applicants know that obtaining a DCO takes 18 months to two years. With known dates for prequalification, planning consents should be required in order to pre-qualify.**

- **The CM design should differentiate between firm and non-firm connections. Non-firm distribution CMUs could be derated by the total MW of non-firm generators in the relevant part of the distribution network.**

Response to consultation questions

Objectives of the Rules and capacity market interactions - Questions 1 – 3

1. Energy markets, ancillary services and the CM can be viewed as distinct markets, offering different products in different timescales. Interactions between these are inevitable. However, it is not necessary to address these markets all at once; rather, the simplest method to secure the lowest cost for consumers is to ensure the coherence of each of these markets individually and thereby achieve a coherent market overall.

2. Given the interactions between the markets, the question of whether design choices in the CM are driving inefficient outcomes in other markets therefore needs to be asked from both sides:

- design choices in network charging have driven inefficiencies in the CM (for example the TNUoS embedded benefit has resulted in new build in the CM being predominantly distribution connected).

- in balancing services, the 'spill' payment has encouraged the growth of non BM STOR.

- the BSUoS embedded benefits has reduced the wholesale cost of embedded generation versus transmission connected generation.

- in the CM, the initial lack of recognition of the limited delivery duration of storage has over rewarded short-duration batteries. Since these can only participate in the response markets, this coupled with other embedded benefits has resulted in overbuild. It is not obvious that the market can reward this build out of short-duration storage and there have particularly been implications for the response market.

- the lack of a locational signal at the distribution level has led to significant volumes of distribution connected generation connecting in the south of the UK where the benefit is greatest. At many locations the Distribution company derives little or no benefit from this generation. The reforms that Ofgem is considering will potentially result in a much more targeted approach to the benefits only rewarding distribution connected generation where this has a direct effect in reducing network costs. This will impact on CM participation and potentially on clearing prices.

3. When approaching each of these market segments Ofgem should focus on addressing issues in that market and only that market. Otherwise we risk making no progress at all – for example Ofgem has recently proposed that the reform of the BSUoS embedded benefit now requires further analysis to understand the impact should the CM suspension not be lifted. Rightful changes should not be delayed until 'all the ducks are in a row'. If there was no CM, the removal of these embedded benefits would still be the correct action to take.

4. Issues such as the lack of a requirement for a firm connection for distribution CMUs are also important to level the playing field. Continuing the work to remove these anomalies will allow true costs of balancing services, capacity and energy to be determined.

Rule change process - Questions 4-6

5. There are two issues here, one relates to a view that more industry engagement is needed in the Rule change process, the second relates the difficulties the EMR DB has in making IT changes in the short window between Ofgem deciding which changes to implement and the start of pre-qualification. Having the CM Advisory Group (CMAG) won't address this second issue.

6. Compared to other codes, the CM change process has far less industry engagement and allows no opportunity for industry to develop and improve proposals ahead of consultation. On the other hand, the requirement to submit self-contained worked up rule changes does ensure that they are well thought out by the Proposer and allows for changes to be made in a short timescale. Energy UK has also worked across its membership to develop proposals raised by its members and submitted them under its title. ENGIE views the rule change process as working reasonably well and fears that adding in the CMAG will introduce delays to making changes.

7. Reasons cited for introducing the CMAG are:

- To incorporate greater industry participation - with 353 proposals having been raised to date and almost three quarters of these of these raised by smaller participants (i.e. non 'traditional' big 6), the current process does not seem to be a barrier to making changes.

- Lack of industry insight into proposals submitted - changes are or should be published as soon as they are notified to Ofgem. Counter proposals can be and are made: for example, the variants on the initial proposal raised by ENGIE to address limited delivery duration for storage. Whilst this did mean that there were numerous proposals for Ofgem to consider, it at least avoided the many working group meetings that can happen under the BSC/CUSC in order that WG members can agree on the best solution, consult, agree alternatives and write detailed reports to make recommendations to Ofgem.

- Code governance – There have been criticisms that under the CUSC change process, the CUSC Panel and working groups are biased towards the bigger companies. The CMAG the advisory group may, like the CUSC groups be populated by companies with sufficient resources. The CMAG may reduce rather than improve market wide representation as it could become more difficult rather than easier for small parties to ensure that their CM changes get thoroughly considered.

8. If the CMAG is to be implemented, ENGIE supports Ofgem's wish to keep the volume and speed of change as per existing processes. If the CMAG is to act as only as a first stage of assessment, then the ability to implement changes in a short period may be able to be retained.

9. Working groups that take many months to finesse a solution should not be introduced. Proposals should therefore meet a minimum standard before they are considered including how they better achieve CM objectives and include legal text changes.

10. To keep the speed of change as now, there could be a maximum time allowed before the CMAG must 'hand over' the change – for example within 2 months of the proposed change being presented. If proposals cannot be made fit for purpose during this time, then it is for the Proposer to rewrite them and resubmit. If the current speed of change could be ensured, then ENGIE would be much more supportive of the CMAG.

11. Urgency should be applied where the current Rules provide an advantage to a subset of CMUs, or they address obvious design failings (derating of storage is a good example here). These change proposals should be implemented before the next pre-qualification to prevent the advantage being perpetuated potentially for 15 years in the case of new build contracts. As per the BSC, criteria are needed to define what is and isn't urgent with the proposer being required to justify the need for urgency

12. ENGIE supports Ofgem acting as the chair of the CM Advisory Group – this will give Ofgem early sight of proposals and may speed up decision making.

Regulatory burden– Pre-qualification Questions 7 – 10

<u>Length of pre-qualification window</u>

13. At 8 weeks long, the current pre-qualification window is appropriate particularly now that it extends into September (i.e. beyond the main summer holiday period). ENGIE sees no need to extend pre-qualification further.

14. What must be avoided is pushing auctions back even further. In the early CM design, auctions were supposed to take place 4 years ahead of the Delivery Year. With auctions now taking place in February, the actual lead time is 3 years and 8 months. Any more shortening of this lead time to accommodate longer pre-qualification could impact on new build timescales.

15. Pre-qualification could of course be extended by starting it sooner. Whilst this would be acceptable to ENGIE, it would be for the EMR DB to determine whether this was feasible given the time that appears to be needed to formulate the demand curve. Availability of staff to carry out pre-qualification and for Directors to sign certificates should remain a consideration when setting pre-qualification dates – the human aspect should be retained.

16. We question whether practically a rolling pre-qualification would work. The Portal has to be closed down for a period to allow the EMR DB to make the necessary IT changes to reflect the new Rules and Applicants need to know what the new baseline is when submitting data.

Planning consents

17. Having a deadline to obtain a Development Control Order (DCO) presents a problem even if the deadline is moved to the FCM as Applicants will aim for the deadline. whenever it is and an unexpected delay outside of an Applicant's control will still prevent it from being able to progress the project.

18. If the deadline is set at the FCM, the Applicant faces a termination fee for failure to obtain consent. Applicants may price this risk into their exit bids. At least if the deadline is prior to the auction, the Applicant can avoid contract termination through simply not taking part in the auction if it doesn't have planning consent. Of the three options put forward by Ofgem, ENGIE would prefer that CP 190 is implemented (i.e. Option 3) - Applicants know that obtaining a DCO takes 18 months to two years, and with known dates for prequalification, they should plan accordingly to meet the prequalification end point.

Simplifying pre-qualification

19. ENGIE agrees that some aspects of pre-qualification could be delayed and supports that those set out in Table 1 should no longer be needed at pre-qualification. Even with these, it must be appreciated that the CM has become increasingly complicated – the CM Rules for example have increased in length from 151 pages in 2014 to 303 pages in the set provided in Annex A to this consultation.

20. ENGIE would also suggest that the requirement to specify the Holding Company should be removed (or the ability to change the Holding Company at any time is introduced) as it seems to serve no purpose and prevents asset sales between the end of pre-qualification and the auction (4-5 months of the year) which is clearly highly restrictive.

Regulatory Burden - Reporting Requirements Question 11

21. ENGIE agrees with the proposals set out. ENGIE submits ITE reports every 6 months to comply with the current Rules for its Ffestiniog refurbishment and see that they have little benefit. Replacing this with a Director signed statement only where there have been material changes will provide the same level of surety to Government but will not incur costs for capacity providers.

22. Annex A sets out that the Director's report must be submitted if:

(ca) Material change when described in 12.2.1(c) refers to:

(i) a change to the schedule submitted pursuant to Rule 3.7.2(b), whereby the relevant Construction Milestone specified range is now at least two months later than originally stated under Rule 3.7.2(b);~~any change covered by 12.2.1(a);~~

23. The construction report requires Applicants to give an earliest/latest date for each milestone which establishes a range. This clause then requires the Applicant to notify where the range is "at least two

months later than originally stated". It is not clear what this means for a range to be two months later. Does it for example mean the earliest date in the range, the latest date in the range or the length of the range itself? it would be clearest to tie this to the latest date in the range – i.e. if the latest date for a milestone is more than two months later then the Applicant needs to submit a Directors' report.

Secondary Trading arrangements

24. ENGIE would prefer that details of Interested Acceptable Transferees are kept in a wholly separate register. If the Capacity Market Register (CMR) is used to store this information, then it will be updated very frequently and there is a danger that a user may unknowingly be using the wrong version of the register (it is already difficult to find the correct version of a Register on the EMR web page). Furthermore, the CMR applies to a single Delivery Year and will not contain details of CMUs that have pre-qualified for any Delivery Year if the proposal to widen who can be an acceptable transferee is adopted. As a more general comment, it would be helpful if the Portal listed the most up to date registers for each Delivery Year first and older versions after that.

25. The EMR DB should maintain the secondary trading register as it has access to the information.

26. Reducing the timescales for registering an obligation trade from 5WD to 2WD would be beneficial but is unlikely to help CMUs with intermittent capacity who may only know that then need to trade out of their CM obligation on the day. Ex post reallocation may be more suitable. Indeed ex-post trades could be agreed privately ex-ante to get around the limitations of obligation trading.

27. Three months also seems excessive for NGESO to notify a Secondary Trading Entrant of a prequalification decision particularly since the NGESO is only assessing applications from individual CMUs rather than having to manage the pre-qualification of over a thousand CMUs.

28. ENGIE agrees that trading should be allowed to start from auction results day for the T-4 auction. ENGIE agrees that there does need to be a' threshold of intent' to avoid speculative applications and bids being made with the sole intention of trading out of the obligation at the earliest opportunity.

29. One of the reasons that a prospective CMU may wish to trade is because it cannot meet its SCM – requiring the SCM to be met before an obligation can be traded away is therefore an unreasonable restriction. The threshold could instead be that the CMU has met its FCM as this would provide assurance of genuine capacity. Transferees should however be required to have met their SCM before engaging in trading as they need to be able to demonstrate that they have the capability to take on obligations.

30. Currently under SPDs, 3 tests have to be done in winter, one of which must take place between Jan – April. The proposal in the consultation that where a Transferor trades away a partial agreement for part of the Delivery Year it only needs to demonstrate output up to the partial agreement capacity during that period doesn't work within this framework. If for example, the Transferor trades away half its agreement for the month of February then it should still need to do all three tests up to the level of its original capacity agreement. It would be very hard to devise a subset of SPD rules (in an already

highly complicated area of the Rules) that would cater for all circumstances. ENGIE believes that for practical and pragmatic reasons, this should not be addressed.

Other Changes to the Rules

Amendments to ALFCO

31. The formula could be adjusted such the interconnector obligation is the lesser of the IST and its metering where there is an ESO action to reduce the output below the IST. We also agree that intertrips should be treated as a RBS.

Differentiating between firm and non-firm connections and derating methodology

32. ENGIE raised CP349 which proposed that only those with firm connections be allowed to pre-qualify for the CM. Ofgem prefers that this issue is addressed by de-rating non-firm connections to account for the likelihood of an interruption. Like ENGIE Ofgem clearly sees the need to address this issue – with new connections increasingly being non-firm allowing these CMUs to participate in the CM whilst continuing to ignore the possibility that they will not be able to generate in a stress event cannot be allowed to continue.

33. To resolve this, Directors could be asked to sign a statement or there could be a box in in the pre-qualification system that is ticked if a connection is firm and a requirement to upload a copy of the connection agreement. Non-firm distribution CMUs could be derated by the total MW of non firm generators in the relevant part of the distribution network. To establish this, the CMU would have to request to the DNO that it provides data on the size of the connection and maximum known potential group output at that connection point for the Delivery Year and how much of this is firm. The Applicant could then self determine its own derated capacity. If for example, a connection point had a capacity for 200MW, 100MW was firm and there was a further 300MW of connections, an Applicant with a capacity of 100MW would state a derating of 33%. This would also need to be adjusted by the Technology specific derating factor.

34. Applicants may view this additional data requirement as a further burden on small scale participation, but it is not unreasonable to ask that participants are able to demonstrate that they have the connectivity to contribute capacity in system stress events.

35. Whilst this solution does not work so well for non-firm distribution connected CMUs seeking multi-year contracts (due to the number of connections at a connection point changing over the duration of a multi year agreement), it is no different to the derating methodology adopted for new build storage or new build renewables where deratings are fixed at a point even though they will be impacted by changes in available capacity in the future.

36. Without knowing the 'firmness' of the Transferee, secondary trading is not the solution to resolve this issue. The Transferee could have a weaker connection than the Transferor and therefore have even less certainty that it could deliver in a stress event.

NGESO's incentives and roles in the CM

37. In general. ENGIE agrees that the CM incentives should, where suitable, be incorporated into the wider ESO incentive framework. National Grid has a plethora of incentives to which Ofgem must devote time to assessing performance. Indeed, it can be a distortion to effective activity as National Grid / the EMR DB focusses on the incentives rather than core business. What should be avoided is paying to incentivise the same thing twice.

38. ENGIE agrees that the demand forecasting incentive should be included in the wider package of demand forecasting incentives. It is however unclear how performance is measured under this incentive due to the four year gap between the amount of capacity being procured and the Delivery Year when demand is known and performance can be measured.

39. NGESO should be required to assist all CMUs seeking to pre-qualify not just DSR or as proposed smaller providers. Limiting the incentive on assistance to just smaller providers is discriminatory.

40. ENGIE does not see why the ESO requires an incentive to engage stakeholders or to help them pre-qualify. This and responding to queries in general in their role as EMRDB should be a basic requirement of the role.

41. We agree that the legal separation of the NGESO role from the TO role mitigates some of the conflicts of interest but it does not mitigate all of them as noted in 7.33.3. Generally keeping the ESO separate from the EMR DB should be seen as a good thing unless it can be shown that the costs of maintaining this separation by far outweigh the benefits of having the comfort that separation prevents any conflict of interest.

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