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Submitted by email

3 May 2018

Dear Mr Copley,

Response from EnerNOC to Ofgem's statutory consultation on changes to the Capacity Market Rules

EnerNOC is grateful for the opportunity to respond to this consultation, to help make the Capacity Market Rules more fit for purpose.

In this submission, we go through the relevant rule change proposals in the order they appear in Annex B of the consultation paper. Where our recommendations differ markedly from Ofgem's minded-to position, we have shown this with bold text. Our comments on drafting are interspersed with those on the proposed decisions.

I would be happy to provide further detail on these comments, if that would be helpful.

Yours sincerely,

Dr Paul Troughton
Senior Director of Regulatory Affairs

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Outline of comments

1 General provisions

1.1 Duration of capacity agreements (CP257)

This proposal, from ClientEarth, points out that the current arrangements are not technologically neutral.

This is indeed the case: new-build Generating CMUs can receive 15-year price certainty – representing a substantial transfer of risk from the capacity provider to all consumers – whereas DSR CMUs (whether new or existing) are limited to 1-year agreements. This is not only discriminatory but also inefficient: it is a deliberate tilting of the playing field in favour of high-cost technologies.

We agree that this distortion should be removed. We agree that to do so will require a change to the Regulations, which Ofgem is unable to do by itself. We therefore **recommend** that Ofgem explain to BEIS that this change is needed.

2 Prequalification information

2.1 Punctuation correction (CP275)

We welcome this correction.

2.2 Clarification of VAT number requirement (CP288, CP307, CP319)

We welcome this clarification, and the change in approach it represents. In previous years, Ofgem has rejected proposals for similar clarifications on the basis that at least some participants had managed to work out how to comply. We continue to believe that it should be possible even for new entrants to read the Capacity Market Rules and understand what they mean. We hope that Ofgem is coming round to this view.

2.3 Removal of unintentional barrier to CHP participation (CP242, CP243, CP261)

These three rule change proposals all seek to address an error in the definition of a “non-CMRS distribution unit” that has the unintended (and illogical) effect of preventing Capacity Market participation by CHP generators which cannot export onto a distribution network.

This is an error, it is important, and it should be fixed.

Ofgem is correct that the error occurs in the Regulations, and so cannot be properly fixed purely by rule changes. We **recommend** that Ofgem implore BEIS to fix this promptly.

Since BEIS appears unlikely to be able to fix the error promptly, it would be prudent to change the rules in the meantime to work around the un-fixed error, if

this can be done without undesirable side effects. Of the rule changes proposed, CP242 seems the best attempt to do this, and we believe it can work. It allows CHPs to be treated as DSR CMUs, with a zero baseline.

In the consultation paper, Ofgem states that such a CMU "does not meet the conditions of qualification as DSR set out in the Regulations", which it paraphrases as: "there must a clear minimum amount of import that is ordinarily required and that a participant will modify their activities to actively reduce the amount that they would ordinarily need for a specific period of time."[1]

While this might be a reasonable definition of DSR, it does not seem consistent with what the Regulations actually say. To us, the Regulations seem to allow the approach set out in CP242. Specifically:

- Regulation 2 defines *demand side response* as "the activity of reducing the metered volume of imported electricity of one or more customers below a baseline, by a means other than a permanent reduction in electricity use".
    - By running a CHP, the metered volume of electricity imported by the customer (i.e. seen by the boundary meter) is reduced compared to what it would be if the generator were not running. The text does not require the meter in question to be the one that is used for the Capacity Market, or for the baseline mentioned to be the one used for Capacity Market settlement.
    - Running a CHP is not a permanent reduction in electricity use. Rather, it is a substitution of imports with local generation.
- Regulation 2 defines *demand side response CMU component* such that it can simply be "a permitted on-site generator".
- Regulation 5(2)(a)(i) allows for demand side response to be provided by causing a customer to "reduce the DSR customer's import of electricity as measured by one or more half hourly meters".
    - This reduction will occur when a CHP runs, and it will be measured by the boundary meter. The text does not require this to be the same meter as is used for Capacity Market settlement.

We therefore **recommend** that Ofgem progress CP242. This is not in any way subverting the Regulations. Rather, it is a pragmatic way to prevent ongoing damage from BEIS's apparent inability to fix an obvious error in the Regulations.

2.4 Calculation of de-rating factors from potentially misleading data (CP318)

We share Ofgem's concern with this proposal. To calculate de-rating factors it is essential to know the availability of each resource. The output data which National Grid has discussed provides no insight into availability.

[1] Consultation paper, p. 19.

2.5 *Arbitrarily restricting new-build status to CMRS units which are not co-sited with load (CP336)*

We welcome Ofgem's intention to reject this Scottish Power proposal. It does not affect us, but we agree that there would be no benefit to consumers from such a restriction.

2.6 *Allowing transmission-connected Private Networks (CP345, CP350)*

Option 2 of CP345 from Waters Wye Associates proposes extending the rules around Private Networks to allow for them to be transmission-connected, as an alternative to being distribution-connected. CP350 from Saltend Cogeneration addresses a similar issue.

We would welcome this change, as transmission-connected Private Networks do exist (we have come across them on customer sites), and there seems no plausible rationale for preventing their use in the Capacity Market.

The consultation paper suggests that consequential changes and further thinking may be required. It looks as if it should be quite straightforward:

- No changes to the Regulations are needed.
- The definition of *Private Network* in Rule 1.2 does not need to be changed.
- Rules 3.6.3(d)(ii), 3.7.3(ba)(ii), and 3.10A.3 simply need to refer to "Distribution or Transmission Network" in each case.

We therefore **recommend** that Ofgem proceed with this, and believe that it ought to be possible this year.

2.7 *Introducing "Storage DSR" technology classes (CP353)*

This Scottish Power proposal seeks to erect barriers to demand-side participation, ostensibly out of concern that battery developers might seek to move their projects "behind-the-meter", masquerading as DSR, so as to avoid the de-rating factors that apply to short-duration batteries.

We have seen no evidence that this is a real issue, or that it is likely to become one. On the contrary:

- Our detailed modelling of the potential business cases for batteries shows that, although short-duration batteries can be optimal for front-of-meter use, behind the meter it only makes sense to install batteries with multi-hour duration. This is because most of their value comes from substantial time-shifts of demand – in response to wholesale price variations, tariff elements, or mismatches with local renewable generation output. We therefore do not expect to see widespread deployment of short-duration batteries behind the meter.

- The business case for batteries depends on long-term revenue certainty. This is why the 15-year contracts available in the Capacity Market were attractive: they guaranteed a useful proportion of the necessary revenue. It was this attractiveness that led to the scramble to change de-rating factors last year. A 1-year contract, which is all that is available to DSR CMUs, makes a negligible contribution to the business case, so will not attract developers.

If this issue is to be addressed (which we do not consider necessary), we do not believe that the approach proposed by Scottish Power is workable.

To take an example of where storage might be used: many customer sites have Uninterruptible Power Supplies (UPSs). They are especially common in data centres and telephone exchanges, where they sustain the operation of critical loads on the site either for the duration of an interruption to the grid supply or until standby generation can be brought online. Durations range from a few minutes up to multiple hours. When such a site participates in a DSR CMU, the storage would be used, but only briefly: to cover the transition from grid supply to local generation. Typically this would be combined with load curtailment on the same site. The duration capability of the storage is irrelevant.

We also anticipate that some aggregators might use storage facilities on one customer's site in conjunction with long-lead-time (or particularly high cost) load curtailment on other sites: they get response from the storage first, then transition to the other load curtailment when it is ready (or if the stress event is still ongoing). This is consistent with the way aggregators already use a mix of loads with quite different characteristics, sometimes alongside generation, to produce the required response in aggregate. The mix that is used can vary substantially from event to event.

We cannot envisage a set of classification rules and de-rating methodologies which would assuage these concerns about short-duration storage without unduly limiting the ability of aggregators to do their job: assembling portfolios of demand-side resources which will provide the necessary flexibility at least cost.

If there is genuine concern about CMUs being unable to respond for the duration of a stress event, then the right way to address this is through the penalty regime. If non-performance penalties are sufficiently material, then providers of every sort of capacity will be incentivised to ensure that their resources can perform adequately.

3 Determination of eligibility

3.1 Remedying of errors in prequalification applications (CP328)

This proposal from National Grid points out the absurdity of capacity being prevented from participating in an auction due to trivial clerical errors in prequalification applications.

While we accept that accuracy is important, we agree with the proposer that the current arrangements do not get the balance correct, and hence act against consumers' best interests. The obvious effect is where capacity needlessly fails to prequalify: this reduces competition in the auction and hence increases the costs borne by consumers. But there is another substantial effect: the deadweight cost of the massive clerical efforts by all participants to try to avoid this fate.

We agree with Ofgem that conditional prequalification – with its requirement for credit cover – would be inappropriate. However, we think some form of intermediate stage is necessary.

The consultation paper points out that the apparently immutable Regulation 69 prevents the correction of errors or omissions in prequalification applications after the Delivery Body has made its prequalification decision. However, this does not mean that nothing can be done. All that is needed is for the Delivery Body to provide the applicant with a "provisional decision" some time in advance (e.g. a week, as suggested in CP328) of their formal decision, allowing time for simple corrections. This would be in no way inconsistent with the Regulations.

We therefore **recommend** that Ofgem either change the rules to introduce such a step, or work with the Delivery Body to develop a workable process outside of the rules, to be used in the next prequalification cycle.

4 Obligations of Capacity Providers and System Stress Events

4.1 Corrections and clarifications (CP279, CP289, CP290, CP304)

We welcome these corrections and clarifications.

4.2 Preventing local issues from triggering Capacity Market Notices (CP323)

We welcome National Grid's proposed refinement. Capacity Market Notices should only be issued in circumstances which are likely to lead to a System Stress Event. Extraneous notices will lead some Capacity Providers to take action needlessly, incurring unnecessary costs.

4.3 *Excusing gas-fired generators of their obligations (CP278)*

We welcome Ofgem's minded-to position to reject this proposal. We agree that this would introduce preferential treatment for gas-fired generators; we cannot see how this would lead to consumer benefit. It is notable that some other capacity markets require generators to provide evidence of a secure fuel supply, and recognise the additional resilience that comes from dual-fuel plant. This proposal would seem a step in the opposite direction.

4.4 *Deadband periods for Capacity Market Notices (CP324)*

We agree with Ofgem's minded-to position to reject this proposal. National Grid should aim to have accurate information about the likelihood of a System Stress Event available promptly, rather than putting participants on standby for an extended period needlessly.

We note that the proposal mentions the potential for "confusion and/or lack of confidence in the process". There is indeed enormous potential for this. We discuss it further in CP327 below.

4.5 *Information provision regarding Capacity Market Notices (CP327)*

We agree with this proposal from National Grid, and we **recommend** that Ofgem accept it. Greater transparency in this regard cannot be harmful, and will go a long way to remedy the current confusion and lack of confidence in the process.

The consultation paper states that "no new evidence has been provided". We disagree. The rule change proposal spells out clearly the information that the System Operator has available and is using, but does not make available to participants. Timely, reliable information is crucial to allow participants to make efficient dispatch decisions.

We reiterate that of all the capacity markets in operation worldwide, the GB Capacity Market appears to be unique in failing to provide dispatch instructions to Capacity Providers, and instead requiring them to guess. This seems a foolish choice with wasteful consequences; withholding relevant information only makes it worse.

4.6 *Portfolio maintenance (Of12)*

Ofgem, the Delivery Body, and the Settlement Body have known since 2015 that it will be necessary to keep track of components of CMUs. Frankly, it should have been obvious even before then. As a reminder, the timeline so far is as follows:

January 2015	CP46 submitted by UKDRA.
April 2015	Ofgem is "minded to consider this proposal further, with a view to making a decision before the first transitional delivery year begins."
May 2015	Ofgem invites more detailed proposals, noting that "an earlier submission will

	allow more time for us to consider the change and make it more likely that we would be able to take the change forward for the following year."
January 2016	CP129 & CP130 submitted by EnerNOC.
April 2016	Ofgem is "minded to take forward CP129 … We recognise there will be some additional administrative costs for the Delivery Body. We think these will be outweighed by the savings from increased competition in the CM."
July 2016	Ofgem: "Since consultation we have engaged with the CM Settlement Body and Delivery Body and understand there are valid reasons for expecting systems for component allocation to not be delivered until 2018."
March 2017	Of12 published by Ofgem.
June 2017	Ofgem: "We noted that the changes would not take effect until 2018 Delivery Year. We will consult on the legal drafting of this change next year."
March 2018	Ofgem: "The current system building blocks are based on CMUs rather than CMU Components, and this granularity of change comes with an implementation burden for the EMR Delivery Partners. In order to introduce these changes into the Rules without disrupting the efficient operation of their systems, we are consulting on the final drafting of our proposal but do not plan to implement the changes until next year, in time for the 2019/20 delivery year."

This latest slip in the implementation timeframe is inexcusable and dangerous.

Thus far, the industry has been lucky: no aggregator has yet been bankrupted due to the lack of component reallocation. But this is just luck, and it is only a matter of time until it happens. Without the ability to replace customers who for whatever reason can no longer respond, aggregators can find themselves in a position where their asset cannot perform as required, and yet they are barred from fixing it.

As discussed in our previous submissions, the status quo is akin to a ban on Generator CMUs repairing faults: if something breaks in your power station, tough luck; you'll probably go out of business. This isn't sensible, and it's not good for reliability.

If an aggregator falls foul of this ban before Of12 is implemented, it will undermine trust in the Capacity Market and in the concept of demand-side management. Taking this risk flies in the face of the Government's many initiatives to promote smart systems and demand-side flexibility. We therefore strongly recommend that strenuous efforts be made to bring in the ability to reallocate components by October 2018.

It may well be impossible to build robust, scalable systems for managing changes to portfolios in the time available. In that case the sensible approach is to build robust, scalable systems for October 2019, and **implement an interim manual process for October 2018**. The use of the manual process can be minimised (so as to avoid an excessive workload and reduce the potential for error) by limiting the number of transactions in the first year. Although this won't allow the full benefit of actively managed portfolios, having the ability to change things when absolutely

necessary will allow an affected aggregator to avoid a crisis, with all the public trust issues that would follow.

We have some specific comments on the proposed drafting shown in Annex E of the consultation paper, broken down below by rule.

Rule 4.4.5

Rule 4.4.5 refers only to "Proven DSR CMU Components." We believe the policy intent is that this ability should be available to all DSR CMUs. This text may have been written on the understanding that a CMU which is prequalified as an Unproven DSR CMU becomes a Proven DSR CMU once it has passed its DSR Test. That would be logical, but does not actually seem to be the case.

We note that the Delivery Body's portal and Capacity Market Registers continue to refer to CMUs as Unproven DSR CMUs throughout the Delivery Year, if that's how they prequalified for that Delivery Year. This behaviour is consistent with the Rules: there does not seem to be a rule that changes an Unproven DSR CMU into a Proven DSR CMU.

To avoid unintentionally restricting portfolio management capabilities only to those CMUs which prequalify as Proven DSR CMUs, you should remove the word "Proven" from Rule 4.4.5.

Rule 8.3.2A

Rule 8.3.2A states that a DSR Test Certificate for one Delivery Year will no longer be valid for the subsequent Delivery Year if changes are made, and states that a new DSR Test Certificate must be obtained. There are three issues here:

1. As with Rule 4.4.5, it is necessary to remove the word "Proven" (twice).
2. It is possible that a CMU might skip a year – i.e. it could participate in the years T and T+2. This seems to be allowed by other rules. To be consistent, this rule should refer to "a", rather than "the", subsequent Delivery Year.
3. The way this rule is currently worded, it could be interpreted as meaning that, even if the CMU is being retired after the Delivery Year, it still needs to undergo another DSR Test, just before the end of the Delivery Year. This test would serve no purpose, and hence would just needlessly deter prudent portfolio management. Ofgem's proposed drafting for CP244 (Rules 13.2.12E, 13.2B.23) gets this right.

Here is some proposed text fixing all three issues:

> Where a Capacity Provider has requested to add and/or remove components from a ~~Proven~~ DSR CMU pursuant to Rule 8.3.4, the DSR Test Certificate will no longer be valid for a subsequent Delivery Year. ~~and~~ Capacity Providers that have added and/or removed components pursuant to Rule 8.3.4 from a ~~Proven~~ DSR CMU that has a Capacity Agreement for a subsequent Delivery Year ~~pursuant to Rule 8.3.4~~ must obtain a new DSR Test Certificate, subsequent to the final component addition or removal during a Delivery Year and no less than six weeks prior to the start of that subsequent Delivery Year.

Rule 8.3.3

In Rule 8.3.3(e)(v), the word “Proven” should again be removed.

Rule 8.3.4(e)

Rule 8.3.4(e) only allows notifications of changes to be made from the start of the Delivery Year. This means that if a Capacity Provider discovers ahead of time that some components in a CMU need to be replaced, they cannot take any action before the start of the Delivery Year. Since it takes 21 Working Days (per Rule 8.3.4(g)) for new components to be added, this means the CMU will not be fit for purpose during the first 21 Working Days of the Delivery Year.

To avoid this unnecessary period of unreliability, Capacity Providers should be allowed to submit a notification sufficiently far ahead of the start of the Delivery Year for the change to be completed in time for the first day. The simplest approach would be simply to remove the text “during the relevant Delivery Year”, as there is no reason for a Capacity Provider to submit an excessively early notification. Alternatively, the window for changes could be explicitly opened on a particular date, which we recommend should be at least 6 weeks before the start of the Delivery Year.

Rule 8.3.4(g)

Rule 8.3.4(g) could be read as if the added DSR CMU Components will not be included until after any Metering Tests have been completed (as this is a condition of 8.3.4(h)(ii)). We think this must be unintentional, as there is no upper bound on how long this could take (as there is no time limit in 8.3.3(c)). This could be avoided by referring only to 8.3.4(h)(i). This would still leave the Capacity Provider with an obligation to complete a Metering Test if required – it just would avoid delaying the change to the portfolio and hence return the CMU to reliable operation sooner.

Rules 8.3.4(i)-(j)

The limits in 8.3.4(j) are problematic. They would be ample for an aggregator with one or two CMUs, but could cause problems for larger aggregators.

The aim should be to encourage aggregators to take prompt action to repair CMUs. These limits instead make opportunities to make changes a scarce resource, which will cause aggregators instead to wait as long as possible before acting, so that they can bundle changes together. This is undesirable.

Alternatively, they could work around the per-aggregator limits by using multiple special-purpose vehicles, each responsible for a small number of CMUs (in a similar manner to many engine farm and battery developers). It seems silly to encourage this.

It is not clear why these limits are proposed – they seem entirely arbitrary. There is no gaming risk, so we assume they must simply be intended to limit the Delivery Body's workload. It might be appropriate to impose these limits while the Delivery Body is using a manual process, but not once they've built a proper automated system (i.e. from October 2019).

If there are to be limits on the number of requests, then Rule 8.3.4(i) becomes important, as Capacity Providers will want to combine requests to the greatest extent possible. There is a problem here, though: component removals under rule 8.3.4(b) take place 5 Working Days after notification, whereas additions take 21 Working Days (or longer, depending on the interpretation of Rule 8.3.4(g)). This means that, if a customer is being removed and replaced in a single transaction, there will be a gap of a few weeks between removal and replacement. If we are going to persist with the idea of limits, then it will be necessary to provide some way for a Capacity Provider to indicate that a particular removal should be synchronised with an addition. But it would be better and simpler to avoid imposing limits altogether (other than for the 2018/19 Delivery Year).

We therefore recommend adding the text "For the Delivery Year commencing on 1 October 2018," at the start of Rule 8.3.4(j).

Rules 8.3.4(m)-(o)

Rules 8.3.4(m)-(o) suffer from the second and third issues discussed in relation to Rule 8.3.2A: implying that a test is needed just before retiring a CMU, and not supporting CMUs that skip a year. These can be remedied as follows:

(m) Pursuant to Rule 8.3.2A, if the CMU has a Capacity Agreement for a subsequent Delivery Year, it must undergo a new DSR Test in accordance with Rule 13.2, or a new DSR Joint Test in accordance with Rule 13.2B.

(n) ~~Where a CMU undergoes a new DSR Test or new Joint DSR Test in accordance with Rule 8.3.2A,~~ The CMU shall remain proven for the Delivery Year during which components were added or removed.

(o) Where a notification(s) has been made pursuant to Rule 8.3.4(b) or Rule 8.3.4(e), and the CMU in question has a Capacity Agreement for a subsequent Delivery Year, the CMU shall be subject to Rule 8.3.2 in the subsequent Delivery Year.

Alternatively, it may be possible simply to omit these rules – or maybe just (n) – as they are largely redundant. (There is a lot of redundancy in the Rules; we do not know how much is intentional.)

Schedule 2

The new text in Schedule 2 is intended make sure the baseline is calculated using only the live components. The wording refers to components which are live "at the time of the System Stress Event". This works when the baseline is being used to evaluate performance during a System Stress Event, but not when the baseline is being used for other purposes – i.e. DSR Tests or Satisfactory Performance Days.

This can by fixed by instead using the phrase “on the day of the Settlement Period or DSR Alternative Delivery Period”.

5 Transfer of capacity obligations

5.1 Minimum trading threshold (CP245)

This proposal seems eminently sensible. We are surprised and dismayed that such a simple modification should require “fundamental changes to systems”. There is a lesson to be learned from this: market systems should not be designed on the assumption that nothing will ever change. Rather, they should be designed to be maintainable, and this should be a core part of their specification. An inflexible system is not fit for purpose. We recommend that Ofgem remember this, and remind other parties of it, when future market systems are contemplated.

6 Testing regime

6.1 Avoiding unnecessary DSR tests (CP244)

We welcome Ofgem’s minded-to position to take this proposal forward, and we consider the approach set out in Annex E for amendments to Chapter 13 to be simpler and better than that in the original rule change proposal.

We are concerned, however at the suggestion that it is appropriate to use New DSR Tests as an extra punishment for receiving a Metering Recovery Payment Notice. Such a notice already triggers the repayment of Capacity Payments. This is punishment enough for all other CMUs; we cannot see any reason to impose extra, costly punishment just for DSR providers. We **recommend** that this is avoided, by also implementing the changes to Rules 13.2A, 13.2C, and Chapter 13A as proposed in CP244.

6.2 Additional window for DSR tests (CP259)

E.ON’s proposal to allow Unproven DSR CMUs to undergo a DSR Test between prequalification and the auction seems sensible. Where Capacity Providers choose this option, it will reveal the CMU’s actual capacity ahead of the auction, so it is represented correctly in the auction, rather than risking a shortfall afterwards. This should make auction outcomes more efficient.

Ofgem states that it has not seen evidence that the time available for DSR Tests is insufficient. This seems to be missing the point: in general, more time is better; in this specific case, the extra information gained by opening this window will improve the efficiency of the market.

7 Schedules & exhibits

7.1 Revisions to the Metering Statement (CP301)

We welcome Ofgem's minded-to approval of this proposal from the Settlement Body, clarifying rules requirements in the light of experience.

7.2 Avoiding unnecessary replacement of metering equipment (CP302)

We welcome Ofgem's minded-to approval of the Settlement Body's proposal to avoid the unnecessary replacement of metering equipment. The benefit of this is obvious, as the Capacity Market is not intended as a full employment scheme for meter installers.

7.3 Baseline calculations when System Stress Events fall on non-working days (CP274)

This proposal from EDF seeks to correct an error in the baselining methodology. The error would only manifest in unusual circumstances. Nevertheless, it is important to get such details right, as failure to do so can undermine confidence in the integrity of the market.

Again we are surprised and dismayed that the system changes required to fix this would be "significant". This change is less urgent than many of the others, so it should go to the back of the queue, but it should not be neglected.

7.4 Judging bespoke metering on its overall accuracy (CP303)

Just as in CP301 and CP302, the Settlement Body is using its practical experience to make a sensible recommendation to avoid unnecessary replacement of metering equipment where "there is no risk to the settlement of the Capacity Market as Overall Accuracy is being maintained."

The Settlement Body has assessed the risks and concluded that there are none. We do not see why Ofgem should not believe them. We therefore **recommend** that Ofgem progress this rule change.