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Dear Sirs,

Response from Enel X to the Capacity Market Review call for evidence

Thank you for the opportunity to provide evidence to support this review. Enel X – formerly known as EnerNOC – works with commercial and industrial energy users to develop demand-side flexibility and offer it into wholesale capacity, energy, and ancillary services markets worldwide. We have done this for many years by altering customers' consumption patterns and controlling on-site generation. To this we have added control of on-site storage and modulation of electric vehicle charging.

We have experience of participating in almost all the capacity markets in existence, and have been closely involved in the stakeholder processes for most of the capacity markets currently under development. We believe there are indeed lessons to be learned from these other markets, and will attempt to convey these here, as well as what we have learned from our participation in Great Britain.

This submission follows the structure of the call for evidence, although we have omitted some sections. Since some of the topics we address cut across multiple questions, this brief index may be useful:

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

Yours faithfully,

Dr Paul Troughton
Senior Director of Regulatory Affairs

1 Need and objectives

Q1 Do you believe there is a need to maintain the Capacity Market? What conditions would be necessary for the Capacity Market to be withdrawn?

We believe a capacity market should be viewed as a permanent feature, rather than a temporary intervention, because it is the lowest-cost means to ensure an acceptable level of security of supply is maintained.

A properly competitive capacity market is not a subsidy scheme. It is a basic commodity market, where the commodity in question is the availability of supply capacity. It should sit alongside commodity energy and ancillary services markets. If investments driven by price signals in those other markets also happen to meet all the capacity requirements, then capacity prices will fall away, leaving the capacity market doing no harm (other than its administrative overhead).

We do not expect this to happen any time soon, as the power system has many challenges ahead. However, even if it did, it would arguably be more prudent to leave the capacity market in place as insurance against future changes in conditions, rather than to scrap it and risk later having to develop a new one in a hurry.

As evidence, we would offer that we are not aware of any jurisdiction that has ever transitioned away from a capacity market.

Q2 Do you believe the current objectives of the Capacity Market remain appropriate?

Since the Capacity Market (CM) has already had considerable unintended consequences – the flurry of diesel farms, in part due to them being the cheapest technology eligible for multi-year contracts – it may be worthwhile spelling out the third objective in more detail, with an explicit reference to technology neutrality. We note that the Western Australian market's objectives do this.[1]

2 Volumes

Q3 Do you think the arrangements outlined in section 3.1 are adequate to ensure sufficient capacity is secured through the auctions to deliver security of supply?

The arrangements are not sufficiently codified for anyone to be able to judge their adequacy. In particular, the final decision about the quantity to procure, along with most other parameters of the market, is left to the Secretary of State's discretion.[2]

[1] Clause 1.2.1(c) of the Wholesale Electricity Market Rules, available from https://www.erawa.com.au/rule-change-panel/wholesale-electricity-market-rules. Clause (e) could be construed as a bias in favour of demand-side measures, but in practice it is consideration of clause (c) that usually ensures balanced treatment. Note that Western Australia's market has suffered a series of detrimental political interventions in recent years, in which the previous State Government bypassed the market operator and the principles-based rule change processes to skew the market such that it would improve the profitability of the state-owned generating and retail company. This is what has made us wary of the potential for political intervention. The current State Government is still working on fixing the damage.

[2] Regulations 12 & 13.

This is extremely unusual.

In most markets, rather than such decisions being left to anybody's discretion, instead the rules set out a process through which a neutral body consults with stakeholders to develop, apply, and refine a methodology to determine each auction parameter.

The political decision making stops at the level of setting the objectives, and the more detailed work is carried out with complete transparency. We would recommend adopting such an approach here.

Ideally, the Secretary of State would appear in the Rules as only a last-resort path of appeal, rather than in more than fifty places. As evidence, we would recommend comparing the Rules and Regulations here to those of a sample of other markets, identifying the opportunities for political intervention: the contrast is remarkable.

Q4 What are your views on the split between the T-4 and T-1 auctions and the amount of set aside?

We consider there still to be plenty of untapped demand-side resources: the level of demand-side participation is well below the levels reached in mature markets,[3] and we do not see any particular reason why customers here should be so very different to customers elsewhere that they cannot provide flexibility.

Hence we believe that the T-1 set-aside could safely be returned to its pre-2016 levels.

3 Investment

Q5 Has the Capacity Market been successful in supporting investment in capacity (new and existing), both directly and indirectly? If not, please identify any changes that need to be made.

It has supported investment, but, due to distortions, this has not necessarily been the most cost-effective investment. The next question addresses a major distortion.

Q6 Do the current 1,3 and 15 year agreement lengths support investment in capacity and do they deliver against the objective of cost-effectiveness?

Multi-year contracts are more valuable to capacity providers than single-year contracts at the same price, because they take away much of the investment risk. They are also more expensive for consumers,[4] because that risk is transferred to them.

[3] There are multiple markets in which the capacity available from dispatchable demand-side resources is 6% to 10% of the system's peak demand. Typically, this is almost entirely from commercial and industrial loads. Successfully engaging residential customers should allow higher penetrations still.

[4] On a risk-adjusted basis.

The decisions to:

(a) ignore contract duration when comparing offers in the auction[5] – hence making multi-year contracts almost always preferable – and

(b) allow only certain technologies to receive multi-year contracts

amount to a tilting of the playing field in favour of the technologies that are allowed multi-year contracts. This is a far cry from "technology-neutral".

Unsurprisingly, this had an unintended consequence: large volumes of diesel farms cleared in the T-4 auctions, these being the cheapest technology eligible for multi-year contracts.

We consider both of these decisions to be errors, and the combination of the two is particularly damaging.

As evidence, we know the effect it has had on us: we have offered less capacity, and at higher prices, than we would have if we had multi-year price certainty. This in an outcome both of how we model our own profitability and risk exposure, and what we know about what customers need to be offered to make participation attractive. In addition, our internal business cases for investment in this country would succeed more often with multi-year price certainty. So, if demand-side resources had not been subject to this discriminatory treatment, consumers would have benefited from greater competition and lower costs.

Looking at established capacity markets worldwide, none of them take this discriminatory approach. Most provide only a single contract length. We are aware of only two mature markets which allow longer-term contracts:

1. **ISO-NE**, which allows new resources to lock in their price and volume for a maximum of 7 years. Crucially, they do this in a technology-neutral way: any new resource is eligible: generation or DSR.[6]

2. **PJM**, which allows proponents to choose New Entry Pricing, which fixes the price and volume for 3 years. However, they will only receive New Entry Pricing if they are the marginal resource in the auction. If their project depends on multi-year revenue certainty, they can make their offer conditional on receiving it: if they are not marginal, they will not clear.[7]

It is worth also looking at Alberta, which is introducing a capacity market. As part of the stakeholder process for this, they have looked at the world's other capacity markets (including ours) in great detail. On this issue, they also took advice from an investment bank and from an economic consultancy. We would recommend

5 The Rules and Regulations make provision for a price-duration equivalence function, to avoid this problem. The consultants tasked with finding the optimal price-duration equivalence function concluded that they could not come up with something which worked perfectly. Unfortunately, a serious error was made at this point: rather than choosing some function which worked only approximately, instead it was decided to choose the most extreme possible approach – of completely ignoring contract length.

6 ISO-NE, Market Rule 1, §III.13.1.1.2.2.4 for new generators and §III.13.1.4.2.2.5 for new demand resources, available from https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1, but note that ISO-NE blocks access to its website from some non-US IP addresses. We can provide copies of the referenced documents if necessary.

7 PJM, Manual 18, §5.3.3, available from https://www.pjm.com/library/manuals.aspx.

reading their rationale for their final choice of 1-year terms for all resources.[8] In summary, they concluded that the benefits of:

- Non-discrimination
- Reducing the risk of over-procurement
- Being a proven successful approach
- Providing better liquidity
- Providing better price fidelity and more frequent market information

outweighed the potential benefits of longer-duration contracts.

We have not seen any evidence that this country is so very different to these others – so much less capable at financing – that discriminatory contract durations are necessary or desirable.

We recommend that, to ensure future cost-effectiveness, the CM should be reformed so that it either:

- Offers only a **single contract duration** to all resources. This could be 1 year, or maybe several.

- Offers all resources a **choice of contract durations**, but with an approximate adjustment applied to the price, such that the longer the duration of the contract, the less it pays.[9] Hence there will be an incentive for participants to choose the shortest-duration contract that their business can tolerate.

4 Delivery

Q7 Should penalties be adjusted to strengthen incentives for delivery during stress events? If so, how should penalties be adjusted? Please provide a view on the methodology and factors to consider when setting penalties.

A capacity market penalty regime should ensure that, if a potential capacity provider is not confident their resource will be available when needed, they will think twice about participating. No participant should consider the capacity market as a no regrets source of free money.

To achieve this, the annual penalty cap should be raised above 1.0× annual revenues. We note that recently-designed capacity markets have reached similar conclusions:

- **Alberta** proposes to set their annual penalty cap equivalent to 1.3× annual revenues, with the following rationale:

8 AESO, Comprehensive Market Design, Final Rationale, §5.4,available from https://www.aeso.ca/market/capacity-market-transition/comprehensive-market-design/.

9 Coming up with this adjustment is a very different and rather simpler remit than the previous work on price-duration equivalence, in which it was assumed that most participants would not have a choice: it should be straightforward to come up with a methodology that works better than ignoring duration.

> The factor of 1.3 scales the total payment adjustment level up above the capacity auction price. A value greater than one ensures that capacity assets failing to deliver are exposed to a net payment adjustment, after accounting for capacity revenues they will receive. A value larger than one also discourages speculative capacity sales because by committing to a capacity obligation the capacity asset is at risk of losing more through poor availability and delivery than through what might be earned through capacity payments. The value is believed to be of a magnitude that is sufficient enough for capacity assets to retain the incentive to deliver on capacity commitments, but will not be so large that new entrants will be discouraged from participating.[10]

- **Ireland** has set the I-SEM stop-loss limit at 1.5× annual capacity revenues, judging that this balances providing a performance incentive against placing excessive risk on capacity providers.[11]

If we were designing the market from scratch, we would include stronger penalties per hour of non-delivery and a higher penalty cap. However:

1. One of the major benefits of having a stronger performance penalty regime is that you can have a simpler, cheaper testing regime, and a great deal less administrative paperwork, because you can rely on the strong incentives on capacity providers to be there when needed. This reduces the capacity market's complexity and costs considerably. However, we fear this may not be achievable here: now that unwieldy and expensive administration and testing regimes have been developed, it seems unlikely that they will be relaxed.

2. It is reasonable to have harsh penalties for capacity providers who are not available when the system operator needs them. However, the current design does not have a mechanism for such a penalty. Instead, performance penalties apply in two distinct circumstances: (a) if the resource is not able to deliver its capacity during a stress event, and (b) if the capacity provider guesses wrongly about when or whether a stress event occurs. The first makes sense, but the second does not. It is not acceptable to force participants to guess whether they are needed and then penalise them for guessing wrongly. Until this is resolved, penalties cannot be greatly increased. This is discussed further in our response to Q11.

In summary: we would support increasing the annual penalty cap, but this should be done in conjunction with reducing the cost of the testing regime and eliminating the opportunities for dispatch errors.

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10 AESO, Comprehensive Market Design, Final Rationale, §8.2.25-28.

11 SEM Comittee, CRM Detailed Design, Decision Paper 2, SEM-16-022, 10 May 2016, §5.4.13, available from https://www.semcommittee.com/publication/sem-16-022-i-sem-crm-detailed-design-decision-paper-2.

Q8 Do the current arrangements relating to credit cover and delivery milestones provide sufficient incentives / assurance that capacity will be delivered, with particular reference to DSR?

As discussed in detail, with evidence, in §2 of EnerNOC's response to the July 2017 CM consultation, non-delivery of DSR does not appear to be a significant problem in any other market, and we have not seen any evidence that suggests it is likely to be one here.

However, if there is a determination that something must be done to gain more confidence in delivery of T-4 Unproven DSR capacity, then we would recommend the following changes, inspired by ISO-NE:

1. Move away from a "big bang" DSR Test for the whole Capacity Market Unit (CMU), which can only take place when 100% of the customers have been signed up and enabled, and so will always tend to happen at the last moment. Instead allow for progressive testing of each customer or batch of customers as they become available.[12]

2. Incentivise early nomination and testing of customers by releasing credit cover as capacity is proven.

3. Further incentivise early nomination and testing, and surrender of capacity obligations which are unlikely to be met, by increasing the level of credit cover required for capacity that remains unproven when the final auction parameters are set for the T-1 auction. For this to be effective, there will have to be some mechanism for the capacity provider to surrender any proportion of their obligation that they no longer believe they can meet, forfeiting that proportion of their credit cover. The deadline for this step should be as late as possible, but such that it would allow replacement capacity to be bought in the T-1 auction.

Unproven DSR CMUs currently have a £5,000/MW credit cover requirement, whereas other new-build CMUs have to post £10,000/MW. It would therefore seem logical for the step up in credit cover in step 3 above to be from £5,000/MW to £10,000/MW.

Q9 Do the termination events and fees need to be adjusted to create the right incentives for delivery? If so, how? Please provide a view on the methodology and factors to be considered.

It is hard to discern the logic behind the current assortment of termination events, timings, and fees.[13] Some actions seem to be considered more heinous than others, but it is not clear why. And the timing of some terminations is perverse, in

[12] Doing DSR Tests in this staggered fashion will not prove that the capacity provider can dispatch enough of its components at the same time to meet its capacity obligation. However, this is not actually necessary, as the satisfactory performance days still require simultaneous performance. A rogue capacity provider would have nothing to gain from assembling a portfolio which could pass the DSR Test but then be unable to demonstrate satisfactory performance, as it would lead to them having to refund all their capacity payments and pay a termination fee.

[13] This is partly because Rule 6.10 is needlessly hard to understand, with the meaning obscured by many levels of cross-references. It would be best if Rule 6.10 (and Chapter 13A, which suffers similar flaws) were rewritten from scratch in plainer language, even if no policy changes are intended.

that capacity providers could find their agreements terminated before they have an opportunity to secondary trade. In the interests of security of supply, it seems logical that termination should be avoided to the extent that there is genuine capacity available.

Q10 Do any other changes need to be made to ensure delivery of capacity by the different types of technology?

Batteries and other limited duration energy storage resources will not deliver capacity during stress events at the most useful times or to the extent assumed in the de-rating calculations, because there is no actionable dispatch signal, so they are bound to guess wrongly about when a stress event is occurring.

To be clear, this is not because batteries are not useful capacity resources. Rather, it is because the current design of the CM does not make effective use of them. This should be remedied by introducing a dispatch mechanism. We discuss this further in our response to Q11.

Q11 To what extent does the CM design ensure capacity resources are used in the most effective manner during stress events? Do you have any ideas on how it can further be improved?

The short answers are "To almost no extent", and "Why do you say *further*?".

This CM is unique in the world in not having any dispatch mechanism. We mean that literally: so far as we can tell, in every other capacity market worldwide – current or planned – the obligation that is placed on participants is to be available for dispatch by the system operator during times of system stress. The ones we have looked at to confirm this are:

- Colombia
- France
- Ireland (SEM & I-SEM)
- ISO-NE
- MISO
- NYISO
- PJM
- South Korea
- Western Australia
- Alberta (planned)
- Greece (planned)
- Italy (planned)
- Japan (planned)
- Ontario (planned)
- Poland (planned)

These markets each use one or more of the following approaches:

- Having an explicit dispatch mechanism for capacity resources, taking merit order into account.

- Making it mandatory to offer capacity resources into energy or ancillary services markets.

- Using reliability options to create a very strong financial incentive to offer capacity resources into energy or ancillary services markets.

In each case, the result is that these capacity markets ensure that, when conditions on the system are tight, the system operator has sufficient resources at their disposal to solve any problems.

The system operator can continue to dispatch the system in the normal way, making the most effective use of all resources. In particular, they can dispatch resources in a merit order, according to their costs and/or offer prices. Hence they can use lower-cost resources first, and only use the most expensive resources when necessary.

Where resources have physical constraints – e.g. battery storage with limits on its discharge duration – there are two basic approaches:

- Dispatch purely on the basis of offer price, leaving it to the participant to adjust their offer pricing (possibly to extreme values) to avoid being dispatched beyond their limits.
- Have more complex offers, so that the limits are explicitly declared to the system operator, who will not try to dispatch beyond them.

Under either approach, the system operator is able to use resources with such limits at the times when they will be most useful to ensure security of supply.

Orderly, efficient dispatch

These approaches achieve several important outcomes:

- When system conditions are tight, the system operator continues operating the system in the usual way, but with a guarantee that all necessary resources are available. This is important because a calm, considered response is less likely to lead to error.
- The system operator can avoid dispatching the most expensive resources until it is really necessary to do so. This is important for economic efficiency.
- The system operator can avoid dispatching storage resources with duration constraints until they are sure that they will still be able to contribute when the system is most under stress. This is important because it maximises their contribution to system security.

To emphasise why these outcomes are important, consider their opposites:

- When the system operator realised that the system was likely to become tight, they could issue an alert that would cause a sudden scramble to maximise the output from all resources, with almost all units adjusting their positions. This would be dangerous, because it would unnecessarily increase the risk of equipment malfunction or operator error.
- When the system operator decided the system had become tight, they could dispatch all resources, regardless of marginal costs. This would be needlessly expensive.

- When the system operator decided the system had become tight, they could immediately start discharging all batteries. This would undermine system security, as some of the batteries could be fully discharged, and hence stop contributing, before the system stress event reached its tightest point.

These seem ridiculous, and yet they are exactly what this CM does: during a stress event, to fulfil their obligations, all capacity resources are required not just to be available for dispatch, but actually delivering.

In the lead-up to a system stress event, **all** Balancing Mechanism (BM) resources with a CM obligation that were not previously planning on producing at the level of their capacity commitment (e.g. expensive or energy-limited ones) are expected to submit a new Physical Notification (PN) indicating that they will self-dispatch to at least that level.

The system operator can manage the resulting oversupply by issuing negative Bid Offer Acceptances (BOAs) to get some BM participants to turn back down again. This might allow them to introduce some element of merit order, as they will try to accept the lowest-priced turn-down offers first, which will tend to come from the most expensive resources. But the sudden changes to almost everything will cause a spike in the system operator's workload and in the potential for technical failures.

(It may be that we do not see so much of a scramble in practice because many participants simply choose not to respond to a capacity market notice, due to a combination of uncertainty [as discussed below] and weak performance penalties. This is not a good thing.)

For non-BM resources, the system operator has no control whatsoever, and there is no attempt to dispatch with economic efficiency in mind or to use any judgement to make the best use of limited resources. All these resources will simply be self-dispatched to deliver on their capacity obligation, based on individual participants' understanding of when the stress event will occur. All resources – even expensive resources and limited-duration batteries – are expected to dispatch from the beginning of the stress event.

It could be argued that volume reallocation allows participants to optimise their response: at times when the demand is not extremely high, so low-cost resources have spare capacity above their load-following capacity obligation, participants with expensive resources could do bilateral deals with participants with low-value resources to have the low-value resource over-deliver, and have the excess delivery reallocated to cover the absence of the expensive resource. In principle, this could work. However, in practice, even if participants had perfect information in real time about the timing and severity of the stress event, the transaction costs and time required mean that they are unlikely to be able to come anywhere close to the efficiency of a simple merit order.

Dispatch errors

Note that the assumption of perfect information is unjustifiable. In reality, participants have very poor dispatch information. Again, uniquely amongst the world's capacity markets, participants in this CM are provided with no actionable information about when they need to deliver on their obligation.[14]

When a capacity market notice is issued, the only information this provides is that a stress event is possible sometime between the specified time (~4 hours after issue) and the end of time. After that, they are expected to look at other published information and use their own guesswork to determine (a) whether a stress event is really going to occur, and if so (b) when it starts, and (c) how long it continues.

This means that participants will often get some or all of these things wrong, resulting in them:

1. Thinking there is a stress event when actually there is none.
2. Thinking there is no stress event when actually there is one.
3. Thinking that a stress event starts earlier than it really does.
4. Thinking that a stress event starts later than it really does.
5. Thinking that a stress event ends sooner than it really does.
6. Thinking that a stress event ends later than it really does.

Errors 1, 3, and 6 are inefficient, as that can lead to high-cost resources being dispatched unnecessarily. For DSR, error 1 really annoys customers, and tends to lead to them resenting participation. For batteries, error 3 could lead to them running out of charge during, or even before, the stress event, undermining their contribution to system security. For all resources, errors 2, 4, and 5 undermine their contribution to system security.

These are obvious, severe, and unnecessary risks. No other capacity market tolerates them: having paid to have a resource available, it makes sense to make every effort to use it optimally. Hence they make the capacity obligation very simple: having made your capacity available, you must then respond to the system operator's dispatch instructions. There is no possibility of the participant guessing wrongly about what they should do and when.

The fact that this CM introduces these unnecessary risks when no other CM does is not necessarily evidence that the design of this CM is wrong. However, it is very suggestive.

It is notable that the methodology for calculating de-rating factors for batteries ignores all of these risks, and instead assumes:[15]

- "All resources can perfectly forecast CM stress events"

[14] As evidence, consider how David Preston from National Grid has to repeat several times every time he makes a presentation about Capacity Market Notices that they are "not a dispatch tool".

[15] National Grid, Duration-Limited Storage De-Rating Factor Assessment, December 2017, pp.11-12, available at https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf.

- "Storage is always charged to the level of its CM contract duration requirement at the onset of a stress event"
- "Storage response is immediate at the onset of a CM stress event"

There are similar implicit assumptions for all other technologies: that they will all know exactly what to do and exactly when. These are equally unrealistic.

This means that the Government is kidding itself about the CM's contribution to system security. Many resources may entirely miss a stress event.

A bad way to deal with this issue would be to further de-rate all non-baseload resources to reflect the effect of the likely dispatch errors. This further de-rating would mean that far more actual capacity would have to be procured. This would be expensive and wasteful. It would be much better to follow the example of every other capacity market: make proper use of all resources by eliminating all 6 types of dispatch error.

Solutions

An orderly, efficient dispatch, without these dispatch errors, can be achieved by introducing a dispatch mechanism.

For BM resources, this is straightforward, as BOAs already exist as a dispatch mechanism. The only change required is to treat positive volumes offered into BM but not accepted in a BOA in a manner akin to the *Declared_Availability* term for Relevant Balancing Services defined in Schedule 4 of the Rules: since that volume was offered to the system operator for dispatch if needed, but it turned out that the system operator did not need it, it is counted as having fulfilled its obligation. This is the approach adopted by Poland, whose proposed capacity market design closely follows this one.

Not all CM resources are well suited to being BM resources. Even P344 and other reforms to widen access to the BM will not change this. In particular, many DSR resources can reliably deliver large volumes of curtailment when needed, but do not have sufficiently predictable consumption to be able to provide any useful PN. These tend to be the most cost-effective sources of reliable DSR capacity, so it is important to make provision for them. The most obvious way to do this would be through some kind of "BM Very Lite" which only acted as a dispatch mechanism for otherwise-non-BM resources during system stress events.

Implementing such an approach would not only directly improve security of supply and the cost-effectiveness of the power system, but it would also, as discussed in our response to Q7, allow strong penalties to be introduced for failure to follow dispatch instructions during a stress event.

5 De-rating

Q12 Do the de-rating factors correctly recognise the contribution made by different technologies to security of supply? What changes need to be made?

We do not think that the current approach of "average for the technology" de-rating factors is a good one. It relies on a form of collective punishment – if one of your peers behaves badly, you will suffer – which seems unjust. Self-nominated de-rating factors, combined with a strong penalties for failing to follow dispatch instructions during stress events, would seem a more sensible approach.

As discussed in our response to Q11, current de-rating factors do not take dispatch errors into account. This should be remedied by eliminating the causes of unnecessary dispatch errors, as we have proposed, not by further de-rating.

It is mentioned in the consultation paper that "some stakeholders" would like to de-rate DSR as if it were a battery. We are aware that some generators are heavily lobbying for this change, as it would reduce the competitive pressure they face.

This is a misguided suggestion, for a simple reason: DSR is not like a battery.

Once a battery is discharged, it can do nothing more: the battery's energy capacity is a physical limit. In contrast, for customers providing DSR, it is a matter of cost: the direct and/or opportunity costs or inconvenience that they incur from reducing their consumption generally increase with the duration of the dispatch.

The shape of the cost-vs-duration curve varies greatly – not only is it different for each customer, but it can be very different for the same customer on different days. We have learned from experience that customers are willing to do a lot more when they know that their actions are genuinely needed than when they are merely being tested.

This means that you should not require long tests of DSR resources to prove how long they can respond for. This will tell you nothing about customers' actual ability and willingness to keep responding during long events. Customers will rightly see this as wasteful, and it will deter their participation. Those that are not deterred will incur needless costs. This would be a very effective way of shrinking DSR's participation, which is probably why it is being lobbied for so hard.

As evidence that this would be the wrong approach, it is worth noting that other markets, some of which have much more DSR, do not do this – e.g. PJM, ISO-NE, NYISO, France, Western Australia.[16]

Some markets (e.g. PJM, NYISO, MISO, CAISO, Western Australia) place limits on how long DSR can be dispatched for (or how frequently, or in which seasons).[17] A popular duration limit is 4 hours, but some are longer. However, no market

[16] In fact, in some cases, such as PJM, the effective "de-rating factor" for DSR is greater than one – i.e. they recognise that 1 MW of DSR is more useful to the system than 1 MW of ideal centralised generating capacity. See e.g. PJM Market Manual 18 §4.3.8.

[17] Having firm limits in place can help reassure customers by putting an upper bound on what they could be required to do. Crucially, these are genuine limits: once they have been hit, the DSR resource is no longer required to do anything, and it will not be penalised for stopping responding. This is logical: if you choose to buy a limited service, then it makes no sense to penalise the provider when they provide exactly what you expected.

requires lengthy tests to prove the endurance of DSR resources, as it is so obviously wasteful. All US capacity markets, and the proposed Canadian capacity markets, require 1-hour tests, chosen simply because all sites can provide meter data at that resolution.

A DSR Test proves that the difficult parts work: that the aggregator can dispatch all the components, and the components can, in aggregate, reduce their consumption by a sufficient quantity when dispatched. Delaying how long the customers wait before increasing their consumption involves no technical challenge – it is just a matter of incurring costs.

A long test would just be an expensive test, not something that provided any additional assurance about anything.

We therefore strongly recommend that:

1. The Rules are not changed to require long DSR tests or long satisfactory performance days, as this would be both wasteful and pointless.

2. The Rules are not changed to de-rate DSR resources on the basis of unwarranted assumptions about what they might not be able to do.

If the Government is genuinely concerned about resources providing adequate response during stress events, it should fix the obvious problems first, by first providing dispatch instructions, so that resources know when they should be responding, and then increasing penalties, so that resources are heavily incentivised to respond to dispatch instructions.

6 Cost-effectiveness

Q13 Do you think there are there sufficient safeguards in place to reduce the risk of over-procurement? If not, what changes could be made to further reduce the risk of over-procurement?

As discussed in our response to Q3, there are few concrete safeguards about anything, because the final decisions are all exposed to political interference. A Secretary of State who was acutely concerned about security of supply would be free to over-react to a perceived problem, and cause the market to over-procure.

7 Competition

Q14 Do you believe that the auctions have been sufficiently liquid to date and to ensure strong competition? If not, how could we improve liquidity and competition?

Liquidity and competition could be improved by removing barriers to entry. One barrier of which we have direct experience relates to generators on private networks.

Where a site has both load and on-site generation, what should matter for CM purposes is the capacity that the generator can export onto the site's private network, displacing imports from the grid. The CM Rules and Regulations mostly get this right: the generator can be metered where it connects to the private network, and the private network owner can make declarations about capabilities and historic performance.

However, the case of on-site generation was overlooked when drafting some definitions, such that on-site generation can only participate in the CM if the private network to which it is connected happens to have an export agreement with a licensed distribution network.

This causes two problems:

- Many sites have no need of an export agreement – e.g. if their on-site demand is always above 10 MW, and their on-site generation can only produce 8 MW, they will never need to export, so will not go to the unnecessary expense of negotiating the capability with the distribution network and installing extra protection equipment to allow for it.

- Some large industrial sites with on-site generation are directly connected to the transmission network, so there is no licensed distribution network involved.

Such sites are currently barred from participation. We have direct experience of this: we have had to tell customers that they are not allowed to participate, just because of these definitions.

This issue has been the subject of numerous rule change proposals,[18] but because a proper remedy requires a change to a definition in Regulation 2,[19] which is beyond Ofgem's powers, it remains unresolved.

Q15 What further changes are needed to better facilitate the participation of new, innovative or smart technologies, including from DSR, in the Capacity Market?

We have already addressed some of the necessary changes:

- Non-discriminatory contract lengths, so that all technologies are facilitated equally – see Q6.

- A dispatch mechanism, so that efficient use is made of all technologies, and the system sees the benefit of highly controllable resources – see Q11.

These changes would go some way towards making the CM "technology neutral" in practice, rather than just rhetorically.

In addition, we detail below several other changes that would either address issues experienced by new entrants and new technologies, or create new opportunities for them.

[18] CP242, CP243, CP261, and CP350.

[19] Specifically, adding "or a private network connected to such a network or to the GB transmission system" to the Regulation 2 definition of "distribution network".

There have been rule change proposals relating to many of these, on which Ofgem has declined to act. We believe that Ofgem sets its bar too high: essentially they tend to ask whether a problem makes participation impossible, rather than whether addressing the problem would enable broader participation, increase competition, reduce costs, or increase efficiency.

Allow secondary trading before the T-1 auction

Some new technologies can be deployed more quickly than conventional generation can be built. There ought to be an opportunity for such technologies to replace other capacity, when it becomes apparent to a capacity provider that some other project is going to fail.

The obvious way to do this is through secondary trading: a failing capacity provider with a T-4 obligation could transfer its obligation to the new entrant. However, this is not always possible at present, because secondary trading is not allowed before the T-1 auction, by which time the original capacity agreement may have been terminated. We have seen this occur: a contemplated secondary trade was abandoned due to this issue.[20]

We recommend that this is remedied by allowing secondary trading at any time.[21] This will provide an incentive for failing capacity providers to find a solution that will lead to the capacity obligation being met. It is preferable to forcing the termination of the capacity agreement and buying replacement capacity in the T-1 auction because:

- It will allow a deal to be struck as soon as the failure becomes apparent, possibly allowing the new entrant 2 or 3 years to deploy their resource, compared to less than 1 year for capacity procured in the T-1 auction. This means that a wider range of technologies will be practicable, making it more likely that the capacity will be replaced.
- It would be worthwhile for the failing capacity provider to offer the new entrant payment up to the level of the termination fee, as well as transferring the capacity revenues. This should make it an attractive opportunity for new entrants.

Reduce risks to participants from supplier settlement metering

Each customer site already has a supplier settlement meter installed, which is maintained and subject to an audit and testing regime that ensures it is accurate.

Allowing capacity providers to use these meters if at all possible is clearly a good idea, and a great deal more cost-effective than installing redundant meters purely for CM purposes. It is standard practice in almost all capacity markets.

This works quite well here, except for one problem: despite the capacity provider having no control over the meter, and no way of knowing about any proposed

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[20] The particular case involved the potential for termination under Rule 6.10(ha), which takes place 3 years ahead of the delivery year, per Rule 8.3.3(a)(i).

[21] Specifically, by changing “T-1” to “T-4” in the first paragraph of Rule 9.2.5(a). It may also make sense to remove Rule 9.2.5(a)(i), which also seems a needless restriction on secondary trading. The principle that should apply is that, so long as the capacity obligation is met, all is well.

changes to the metering installation, they bear the consequence of any changes. The same applies if the customer's supplier appoints a different half-hourly data aggregator (HHDA). Specifically:

- Rule 8.3.3(f), together with its cross-references, requires capacity providers to notify the Delivery Body and Settlement Body in advance of any changes to the "metering configuration", "metering arrangements", MPANs, and meters, obtain their prior confirmation that the change is acceptable, and in some cases obtain a new Metering Test Certificate afterwards. Failure to do this triggers Rule 13A.2, which leads to them needing to undertake a new, mid-year DSR Test, and repay Capacity Payments for some period.

- Data from the supplier's meter flows from the customer's supplier's HHDA to the Settlement Body, without the capacity provider having any visibility. The capacity provider requests that the supplier instruct the HHDA to establish a "D0357 flow", and they can later check with the Settlement Body that the data is being received. However, if the HHDA for the site changes – either at the whim of the supplier, or because the customer has changed supplier – then the flow will stop, and the capacity provider will have to start from scratch to re-establish it. Unfortunately the capacity provider has no way of knowing this until some settlement process (e.g. for a system stress event, a satisfactory performance day, or a DSR Test) fails for lack of data.

  Since the results of many of these processes are needed against a tight deadline, and again the capacity provider has strict liability for failing to present the resulting certificates before the deadline, undetected failure of these data flows can lead to penalties, withholding of capacity payments, or termination.

- There is a further subtlety with the data flows: even if the data is flowing, it may not be of good quality. For example, it may be that the real meter data is unavailable, and gaps are being filled with substituted data, based on the site's typical consumption. This is standard practice for retail billing, but does not work for DSR, as we are interested in measuring how atypical the site's consumption became when it was dispatched. Unfortunately, the data quality flags – showing whether data is real or substituted – do not make it all the way through the process to the Delivery Body, so they may attempt calculations on the basis of substituted data.

These problems are compounded by an unwillingness of the Settlement Body or the Delivery Body to accept data from other metering systems – or from the same metering systems but via different paths – as evidence that the data that they hold is erroneous.

So far as we are aware, no capacity provider has yet fallen foul of Rule 13A.2 due to actions of the customer's supplier, but it is bound to happen unless changes are made. We do know that at least one participant has suffered withholding of capacity payments because of data flow issues affecting satisfactory performance day calculations. In this case, they had the correct data from the meters, but were unable to get the HHDA to deliver it to the Settlement Body via the expected path soon enough.

This seems wrong in principle: responsibility for any action should only lie with a party that has some power over the action. Making capacity providers liable for things over which they have no control unnecessarily increases their risks, and hence increases the minimum price at which capacity can sensibly be offered. Where this leads to penalties or terminations that affect participating customers, it will undermine customers' confidence in the idea of participating in electricity markets. They will perceive that too many things can just randomly go wrong.

There are several aspects to the solution:

- Capacity providers should only be punished for failing to inform the Settlement Body or Delivery Body about some metering change if it was a change that they initiated or of which they should have been aware.
- The Settlement Body and Delivery Body should be given leeway to accept data from different sources where something has evidently gone wrong with the primary source.
- The Settlement Body should routinely monitor the data they are receiving – both for continuity and for quality – and automatically alert the associated capacity provider whenever there is an issue.

Allow lower-cost, less disruptive bespoke metering

Of all the markets we participate in, this CM has the most expensive metering requirements – in terms of direct costs, disruption for customers, and administrative hassle. If you exclude the markets in which we're having to provide sub-second metering, and look just at ones with 5+ minute resolution, the comparison is not even close.

Metering costs have the greatest impact on technologies that use aggregations of large numbers of sites: effectively they increase the lower bound on the amount of capacity that a site must provide for participation to be worthwhile.

The Settlement Body has given informal guidance that the only sure way to get a bespoke metering installation approved is to install everything from scratch. Any attempt to be efficient and to minimise disruption to customers (avoiding the multi-hour site shutdowns that installing CM-compliant metering often entails) by making use of existing equipment is fraught with danger.

The costs and disruption involved are so great that we have had to tell customers whose sites happen to be configured such that they would require bespoke metering that it is not worthwhile for them to participate. This is particularly the case for sites which will not be able to provide much capacity.

This can be remedied by revisiting Schedule 7 of the Rules, giving at least some thought as to how the overall benefits of infinitesimally more accurate metering compare with the incremental costs.

Schedule 7 appears to have been written with baseload power stations in mind, where:

(a) Any inaccuracy affects a huge amount of energy during the year, and hence huge revenues.

(b) The revenue at risk is proportional to the maximum rated throughput of the connection, since it will usually operate near full power and be paid for everything it generates.

(c) It is straightforward to meter all relevant flows with only a small number of metering installations.

(d) Since the power station will operate almost all the time, it is useful to have a redundant set of meters, so that one set will continue recording data while the other set is serviced or repaired.

None of these are the case for bespoke metering of DSR CMUs:

(a) Revenues are a lot smaller, since they are only for capacity, not energy.

(b) The capacity obligation can be a great deal smaller than the rated capacity of the connection (e.g. a 100 MW plant might have only 10 MW of flexibility).

(c) The topology of the site's switchboards might necessitate multiple sets of meters.

(d) Dispatches are quite rare, so interruptions in the meter data during servicing may be tolerable.

It seems likely that such a reassessment would lead to some of the following changes:

- The thresholds for Tables 1-4 being based on the site's maximum capacity contribution, rather than the rated capacities of the circuits.
- The accuracy requirements in Tables 1-4 being moderated.
- The check metering requirement in clause 15A being removed.
- The separate CT and VT accuracy class requirements being removed, as the overall accuracy of the calibrated metering system is all that actually matters.
- The option of some form of type approval, rather than individual testing and paperwork, when dealing with large numbers of similar devices with embedded metering functionality. The obvious use case for this is electric vehicle charging points.

In addition, where bespoke meters are only needed to exclude the contribution of renewable generation at a site providing DSR, the Settlement Body should be given the ability to accept any other available meter data that would serve the purpose, or to ignore it altogether in *de minimis* cases. At present, such customers are effectively disqualified from participation, due to the prohibitive bespoke metering costs. This seems particularly perverse since the renewable generation's contribution to a site's performance will usually be zero or negative.[22]

Allow DSR Tests at any time

At present, DSR Tests are not allowed "during the Prequalification Assessment Window for any Capacity Auction".[23] This seems to be an attempt to limit the Delivery Body's workload. However, so far as we can tell, it was only done on a hunch – there is no evidence of any analysis showing:

- That the restriction would actually reduce the Delivery Body's costs.
- That any cost reductions for the Delivery Body would not be dwarfed by those that could be achieved by adopting an efficient, automated process for analysing DSR Tests.
- That any Delivery Body cost savings would outweigh the increased costs to all affected participants from restricting their flexibility in carrying out DSR Tests.

The DSR Test is a crucial step for DSR CMUs. For new resources, it is the equivalent of the commissioning test for new power stations: it is the very last step before the resource is fully operational, and it cannot be carried out until all engineering works on all sites are complete.

There are no similar restrictions on commissioning tests for other technology types: they can be carried out whenever the resource is ready. There are financial consequences if the resource is not actually commissioned before the delivery year, but no artificially early deadline imposed purely for administrative convenience.

This year, the prequalification assessment window started in late September, so the ban on DSR Tests in this period is not particularly inconvenient – resources had to be very nearly ready by that time anyway. However:

(a) There is no guarantee that timing in future years will be similar. There could even be separate prequalification assessment windows for the T-1 and T-4 auctions. The dates are chosen each year at the discretion of the Delivery Body and the Secretary of State, and their decision can be announced very late in the process.[24] This could lead to capacity providers suddenly having to reschedule works to be months earlier. Other technologies are not exposed to such vagaries.

(b) The ability to reallocate DSR components, once Of12 is implemented, while welcome, will lead to more DSR Tests having to take place, with

[22] If the on-site renewable generation were not excluded, then it would contribute both to the baseline and during a system stress event. System stress events are much more likely to occur at times when renewable contributions are low. In these circumstances, the renewable contribution would contribute more to the baseline than during the event, cancelling out some of the DSR that the site delivers. This is undesirable for the customer and aggregator, but preferable to not participating at all due to metering costs. Crucially, there is no way it could be construed as cumulation of State Aid.

[23] Rules 13.2.3 & 13.2B.3.

[24] Rules 2.2.1 & 2.2.2.

different timing requirements. This will increase the costs and inconvenience caused by this unnecessary restriction.

This issue can be remedied by removing Rules 13.2.3 & 13.2B.3.

Use scalable processes for aggregated resources

Aggregators are required to provide the Delivery Body with information on all components that make up a CMU, including MPANs, addresses, postcodes, and grid references. For Proven DSR CMUs, this is ahead of prequalification; for Unproven DSR CMUs, it is ahead of the Delivery Year, per Rule 8.3.3A, and as part of the Metering Assessment, per Rule 3.10.2(b).

The process for doing this through the Delivery Body's "portal" website is workable when dealing with one CMU with a few components, but not for large aggregations. It requires the user to do manual data entry for each component separately. As evidence, please examine the Delivery Body's prequalification guidance.[25]

It requires a massive expenditure of clerical effort to complete this data re-entry task with an acceptably low error rate. The additional costs and risks associated with this process hinder the growth of demand-side participation.

Aggregators already have all of the relevant information in machine-readable form, because they need it to run their businesses. What is needed is a way to convey structured information about multiple components to the Delivery Body without re-keying.

A highly-scalable approach would be for the Delivery Body to provide an Application Programming Interface (API) that allows participants' systems to interact directly with their systems. A crude but adequate approach would be for the Delivery Body to provide a CSV file template, and documentation of the valid field values, that participants could then populate with the required information, with one row per component.[26]

Get the details right on component reallocation

Individual customers are not always reliable. However, large-scale aggregations of them can be. The long-overdue framework for component reallocation is at last scheduled to be implemented in 2019. This has the potential to make aggregated participation more reliable and more cost-effective, and also to invigorate competition between aggregators.

Unfortunately, as currently proposed,[27] the framework will have two serious shortcomings:

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[25] In v13.0 of the 2018 Prequalification Guidance, available at https://www.emrdeliverybody.com/Prequalification/CM%20Prequalification%20Guidance%20v13.0%202018.pdf, see slides 78-79, 206, & 211-217.

[26] Interestingly, the Delivery Body already asks for much of the information to be provided in tabular form in a Metering Assessment Template. See slide 217 of v13.0 of the 2018 Prequalification Guidance. Unfortunately, this is in addition to, rather than instead of, laboriously re-keying it in their portal.

[27] Annex E of Ofgem's 5 July 2018 decision document.

- It has unnecessary transaction and component limits, which will undermine the reliability and efficiency benefits, by making opportunities for portfolio management a scarce resource to be hoarded, discouraging preventative maintenance.

- It has unnecessary timing constraints, which will undermine the competition benefits by making it difficult for a customer to churn between aggregators.

The **transaction and component limits** are in proposed Rule 8.4.5(j), limiting each Capacity Provider to 5 transactions per year, adding no more than 20 components in total. The intention appears to be to limit the workload for the Delivery Body and the Settlement Body. Applying some limit might make sense if they were going to use labour-intensive processes.[28] However, they are not going to do this: the desire to build an automated system is the reason the introduction of this mechanism has been further delayed to 2019.

The proposed limits would make this mechanism almost useless for us. In the 2017/18 Delivery Year, we provided 109 MW from several DSR CMUs containing a total of 159 components. For the 2020/21 Delivery Year, we already have a 500 MW commitment from DSR CMUs in the T-4 auction. If we filled this with customer sites that provided the same capacity, on average, as those in this year's portfolio, we would need 728 components. In practice, increasing DSR penetration depends on enrolling smaller customers, so we expect to have well over 1,000 components. The 20 customer limit would mean that we would be able to replace less than 2% of our portfolio. It is unrealistic to expect 98% of customers to remain engaged and reliable.

An aggregator could partly work around these limits by splitting the ownership of their CMUs between several different companies, each of which would have their own quota. It seems foolish to encourage this practice.

The **timing constraints** are in proposed Rule 8.3.4(e). They prevent a notice to add a customer being submitted before the start of the Delivery Year. This poses a particular problem for a customer who wants to churn between aggregators.

If Aggregator A has them in CMU A, and CMU A has capacity agreements for Delivery Years Y and Y+1, and the customer wants to move to Aggregator B's CMU B for Year Y+1 – with the agreement of both aggregators – then there is no workable way to do this. Since they are in CMU A for Delivery Year Y, they cannot be added to CMU B before Delivery Year Y+1. However, the timing restrictions prevent Aggregator B from submitting the notice until the start of Delivery Year Y+1, which means it will not take effect until the second month of the Delivery Year. This means (a) that the customer cannot contribute capacity at all for a month, and (b) that the customer cannot contribute to a DSR Test on CMU B,[29] making their capacity much less useful to Aggregator B.

[28] As they do for STOR, which apparently relies on faxes, and yet still allows more than 20 changes per year, affecting an unlimited number of components.

[29] This would have to be carried out before the start of Delivery Year Y+1, if CMU B had some component changes made to it during Delivery Year Y.

These timing restrictions will make transferring between aggregators quite unappealing to customers, as they will be of limited value to the new aggregator for the first Delivery Year. This kind of friction will limit the competitive pressure.

Introducing Of12 with these limitations would incur all the implementation costs but bring very few of the benefits. We therefore strongly recommend that it is introduced:

- Without Rule 8.4.5(j). Or if it is felt essential to have some limit, then make it comparable to the STOR limits, or proportional to the number of customers in the CMUs.
- With notices under Rule 8.3.4(e) allowed before the beginning of the Delivery Year.
- With notices under Rules 8.3.4(b) and (e) allowed to be forward dated, such that the changes take effect on a specified date,[30] allowing coordinated transfers on the first day of the Delivery Year.
- With DSR Tests for future Delivery Years taking into account forward-dated transfers that will have completed by the start of the Delivery Year.

Q16 How could we go about allowing augmentation of batteries?

The Capacity Provider should be allowed to offer the additional de-rated capacity resulting from the increased duration capability into future auctions as if it were a separate, new resource. Any shortfalls in performance compared to the total expected from the combined resource should be allocated first to the newest CMU.

Q17 Please provide any other ideas on how to improve cost effectiveness of the Capacity Market.

As discussed in our response to Q15:

- Simplifying bespoke metering requirements would be an important step to reduce direct costs.
- Administrative costs could be reduced by improving the systems and processes for handling data about large numbers of components.

The other change which would significantly reduce costs would be to remove Regulation 69(5). It is this regulation (which did not apply to the first few auctions) that prevents minor administrative errors in prequalification submissions from being corrected: everything must be right first time, or the submission will be rejected, with no possibility of successful appeal, no matter how trivial the error.

Since this regulation was imposed, industry has collectively put enormous effort into avoiding errors in their submissions. It is such a high-stakes endeavour that it

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30 So long as the date is at least the number of Working Days in the future as required by clauses (c) and (g). Alternatively, rather than choosing a specific date, there could simply be the option that the addition or removal should happen between Delivery Years.

is typical for a Capacity Provider to have three different staff members review each submission and all its attachments. The result of all this effort is that the number of rejected CMUs is merely worryingly high, rather than obviously absurd.

It is good to try to be accurate, but counterproductive to aim quite so high. Improved paperwork accuracy and increased employment for clerical staff in the utility industry were not amongst the objectives of the capacity market. So, much of this administrative effort is merely reducing the cost-effectiveness of the capacity market.

8 Unintended consequences

Q18 What are the main distortions in competition that need to be addressed to ensure a level playing field in the CM auctions?

The obvious distortion is the unequal treatment of different technologies with respect to contract lengths, which skewed the technology mix towards diesel farms, as discussed in our response to Q6.

We note the comment in the call for evidence that “it has been suggested that developers of short-duration batteries may be encouraged to locate behind the meter to benefit from the higher de-rating factor attributable to DSR”. We agree that it would be unreasonable if a battery developer installed what would otherwise be a standalone battery system on a customer’s site, so that they could treat it as a loophole to work around de-rating. However:

(a) We are not convinced that this is a real threat, as a 1-year capacity agreement is unlikely to be much help in the battery developer’s business case.

(b) In the business cases we have been seeing for behind-the-meter batteries – both in GB and elsewhere – the batteries have multiple hour durations because this is optimal for the most important value streams available to behind-the-meter batteries.

(c) We are struggling to come up with a method to prevent this behaviour without unintended consequences. For example, a customer’s site that is part of a DSR CMU may well have some short-duration storage which might contribute to the CMU’s performance in combination with other resources which need more notice but can endure for longer. Simply asking whether storage is involved and how long it lasts for would not represent this situation accurately.

We believe it is important not to undermine the ability of aggregators to put together clever combinations of resources to deliver the required performance reliably and at lowest cost. This issue does not seem important enough to risk that.

Looking at other capacity markets worldwide, by far the most common approach is to be “technology agnostic” about what happens behind the meter on customer sites. The market operator does not attempt to micromanage exactly what actions a customer might take. What matters is that the portfolio as a whole meets its commitments. The aggregator is held accountable for ensuring this.

Q19 Are there distortions in the interaction of the various markets (wholesale, ancillary, CM) or their charging arrangements which impact the effectiveness of the CM?

As discussed in our response to Q1, it is important that the CM should work seamlessly alongside the other markets, as it is their combined price signals that should drive efficient investment and operation. Simultaneous participation in different markets should be allowed in all cases except those few combinations that would require contradictory actions.

As detailed in our response to Q11, there should be close integration between the CM and the BM, to allow for orderly, efficient dispatch of CM resources. Without this, responses from CM resources will be disorderly, and the system operator may struggle to use the BM to compensate.

In addition, some refinement is needed over how the markets interact:

- The Rules seem to have been written with the assumption that the distinction between BM and Non-BM resources is profound, such that nothing will ever transition between the two states. The many work-streams on widening BM access invalidate this assumption. The CM Rules (and those for other markets) should fully support Non-BM resources becoming BM resources (or vice versa), even part way through a Delivery Year. Note that this transition could involve just some components of a CMU.
- The Relevant Balancing Services are defined in Schedule 4 of the Rules in a very restrictive way: naming specific National Grid products and referring to particular terms in their contracts. National Grid has embarked on a comprehensive overhaul of its ancillary services. It seems likely that several stages of these reforms will invalidate definitions in Schedule 4, with no respect for CM Delivery Years or change cycles. To avoid unintended consequences, it will be necessary either to update Schedule 4 rapidly and frequently, so that it keeps pace with the actual ancillary services products, or (preferably) to use more principles-based definitions, which will not then need to be changed to match every small detail of the product and service reforms.

9 Institutional arrangements

Q30 To what extent do the current institutional arrangements support an effective change process? Please provide suggestions on how issues can be addressed.

The current split between the Rules and the Regulations, with the Regulations being extremely hard to change, is unhelpful.

It is also extremely problematic that no consolidated version of the Regulations is publicly available: this leads to time being wasted and mistakes being made.

Ideally, there should be a lot less content in the Regulations. They should set the high-level principles, but nothing more, leaving all the details to the Rules.

Where it is necessary to amend the Regulations, this should be properly coordinated with the Rule change process. At present, Ofgem cannot progress some of the Rule changes proposed because they would require consequential changes in the Regulations.[31] Since only the Government has the power to change the Regulations, Ofgem should have a defined process to request that the Government does this as necessary to support the Rule changes.

Q31 To what extent do the defined and allocated roles and responsibilities support effective administration and delivery of the annual processes related to pre-qualification, delivery and payments? Please provide suggestions on how issues can be addressed.

For prequalification and some of the delivery processes, the answer is "badly". There seems to be something awry with the Delivery Body's incentives. As discussed in our response to Q33, their behaviour is very different to that of other capacity market operators.

From a Capacity Provider's perspective, it seems that the Delivery Body is permanently on the defensive, looking at all times for the course of action that their lawyers tell them puts National Grid at least risk. Actually running an efficient, effective market does not seem to feature in their objectives at all.

We are not criticising the staff. We are sure they have good intent. But there is clearly something wrong with the environment in which they have to operate. It is important to understand why the Delivery Body behaves as it does – we do not know – and to fix the cause.

Payments seem to be working well.

Q32 Please provide any suggestions you have for improving the management of fraud and error risk.

The main risks that errors currently pose to the CM come not from the errors themselves, but from how they are dealt with: they can lead to real capacity being excluded from participation.

As discussed in our response to Q17, participants put in an inefficiently high level of effort into avoiding such errors, because the consequences are so grave.

The risks could be reduced by allowing errors to be corrected – both at the prequalification stage and later in the capacity cycle – so that minor administrative errors (such as mis-spelling "Ltd" as "Limited", or providing too many digits in a grid reference) will not lead to capacity being excluded. These kinds of rigorous,

[31] For example, the private network problem discussed in our response to Q14.

unforgiving checks seem entirely pointless – they certainly have nothing to do with fraud prevention.[32]

Q33 Are there any lessons from overseas capacity mechanisms that could be useful in improving the GB Capacity Market?

As discussed in our response to Q11, every overseas capacity mechanism has some form of dispatch mechanism. Something similar should be adopted here.

In terms of governance and administration, it is worth taking a close look at PJM and ISO-NE, as they are both quite mature.

Change processes

Both markets have quite involved stakeholder processes. PJM's is particularly elaborate, involving sector-weighted voting, one vote per parent company, and other safeguards.[33]

The Federal Energy Regulatory Commission (FERC) oversees both markets. Any changes to the rules or the tariffs have to be submitted to FERC for approval. This is a rather formal legal process which involves a lot of scrutiny. If a proposed change is not a simple and obvious, or somebody formally opposes it, it can go as far as requiring testimony, oral hearings, cross-examination, etc.

Dealing with ambiguity in the rules

The very thorough review processes mean that there seem to be fewer drafting errors and ambiguities than we see here. However, they do still occur. They are resolved by the system operator lodging an "errata" filing with FERC proposing corrected wording. While they are waiting for FERC's ruling on the corrected rule, they can operate under the new rules. However, all decisions under the new rules are "subject to refund" – meaning that they would have to be unwound if the new rules were not approved.

PJM has never done a whole auction "subject to refund", because the level of uncertainty and the financial risk would be huge. However, they have taken various actions on that basis when they have found confusing, incomplete, or conflicting rules for things such as registration processes, measurement and validation, etc. This approach allows the problem to be solved quickly – minimising disruption to affected participants – where the solution is obvious.

With ISO-NE, there are clearly some features in the tariff which they see little point in applying, so they have minimised operational requirements for them to the point that they are almost non-existent. Presumably this is because the operational rules are easier to change than the tariff.[34]

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32 As evidence, consider the Delivery Body's 2018 Prequalification Guidance, v13.0. The fact that it runs to 242 pages suggests that this may be an overly elaborate process. Of the "Common Errors" identified on slides 130-150, it is hard to identify many which actually relate to fraud risk.

33 These processes are spelled out in excruciating detail in PJM Manual 34, available from https://www.pjm.com/library/manuals.aspx.

34 This seems similar to the split we have between regulations and rules.

Dealing with errors by participants

Both markets have processes which are similar to our prequalification process, as well as many other things that have to be submitted by particular deadlines. But the attitude with which they are administered is very different.

With PJM, where a participant makes an error in their submission, the staff processing the submission typically get in touch with the participant to explain why what they have submitted is non-compliant, and either ask for it to be resubmitted with the error corrected, or simply correct the error themselves (with the participant's approval). We have experienced this many times. Sometimes these corrections take place after the official submission deadline. It seems that their aim is to operate the market efficiently by avoiding losing real capacity through trivial administrative errors.

In ISO-NE, there tends to be some back and forth before submitting prequalification materials, to make sure that what is being prepared will meet their requirements. This is somewhat comparable to the "surgeries" that the Delivery Body held last year, except without the caveat "of course, nothing we say is binding; we may decide something different after you have submitted; you should probably get your own legal advice" which accompanied most advice given in the surgeries.

Such an approach means that real capacity is not excluded from the market unnecessarily. Participants take reasonable care with their submissions, but not the extreme and expensive precautions needed in this CM.

The Delivery Body behaves very differently from these other capacity market operators, but it is not clear to what extent this is caused by rigidity in the Regulations or Rules, quirks of the legal framework, financial incentives, or organisational culture.

We think it would be worthwhile comparing and contrasting the Delivery Body's circumstances with those of several other capacity market operators, to work out what needs to be changed.