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Submitted by email

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Dear Ms Dowey & Mr Quinn,

Submission to the second consultation on the detailed design of the capacity remuneration mechanism (SEM-15-014)

EnerNOC is grateful for the opportunity to provide further input to this important design process.

In sections 2-8 below, we respond to those of the questions in the December consultation paper on which we have a useful view, but first we have a brief comment on the SEM-15-103 decision paper.

1 Comment on decision paper position on energy payments

We welcome the SEM Committee's decision only to pursue options that allow for independent aggregation.

The proposed hybrid approach, under which DSUs will only be required to pay RO difference payments to the extent that they fail to deliver the required demand reduction, is an appropriate compromise given the limited time available before I-SEM Go-live.

It is not, however, a sustainable approach for the medium term. This is because it prevents DSUs from participating in the energy markets and because it delivers energy market price signals to the wrong party.

Under this approach, when an aggregator dispatches a DSU to reduce demand, it will cause the suppliers of the customers within the DSU to go out of balance. If the energy market price is high at the time – e.g. because there is scarcity – then this will deliver a windfall gain to the suppliers, which seems inappropriate, as they had no part in the dispatch.

As well as causing unearned windfall gains in the situation described above, this approach also puts independent aggregators at a competitive disadvantage compared to suppliers. The operator of a DSU must generally pay participating customers to reduce their demand. If the DSU is being operated by the customer's supplier, the resulting imbalance will provide an energy market revenue stream to fund these payments. An independent aggregator will have no such revenue stream, and hence must make provision to fund dispatch payments out of their capacity revenue. This will tend to make capacity offered from independent aggregators unnecessarily expensive.

Allowing DSUs to participate in energy markets avoids this distortion and provides a more level playing field between suppliers and independent aggregators.

Hence, in our view, the hybrid approach should only be considered as an interim measure. Design work should be started as soon as possible on allowing direct energy market participation by DSUs, so that it can be implemented within a year or two of I-SEM Go-live.

2 Cross-border issues

We do not have detailed comments on the various options presented. We can see the theoretical attraction of providing I-SEM price signals to cross-border capacity, but remain skeptical that it can be done in a way which is fair and practicable and likely to have any real effect on investment and operational decisions in other regions.

Fairness is important: if capacity payments are to be made to non-local resources, either they should be subject to just as strong a performance assessment and penalty regime as local resources, or their contribution should be further derated to reflect the lower expected reliability.

As explained in the consultation paper, none of the options is particularly good: each either provides poor, inappropriate, or unpredictable price signals, is excessively complex, or would become unworkable in the presence of an additional interconnector. Or some combination of those issues.

It seems fair to say that cross-border participation in capacity remuneration mechanisms is an unsolved problem. Comparing the various imperfect options, the “netting off” approach seems least likely to produce perverse or unpredictable outcomes, while having the merit of being relatively simple.

3 Secondary trading

A) *Do respondents agree that direct secondary trading of Reliability Options should be permitted?*

Yes. We agree that direct secondary trading is preferable to “back-to-back” trading for the reasons given in the discussion paper.

In addition, direct secondary trading will be essential for demand-side participants until they become able to participate in the energy market: before then, they will not have access to the energy market cash-flows required for "back-to-back" trading.

B) Should secondary trading of Reliability Options be via an organised secondary platform? If so, which one of the options is preferred?

Yes. It should be via a mandatory centralised market.

A centralised market is essential for transparency and liquidity. Its absence would severely disadvantage smaller players and new entrants. The idea of an optional centralised market makes no sense: it would incur all the costs of the mandatory approach, without necessarily delivering any of the benefits.

C) Do respondents believe that "back-to-back" trading to lay-off exposure to difference payments should be permitted?

No. Such "back-to-back" arrangements would reduce transparency.

I. Is there likely to be sufficient demand for secondary trading to justify the cost of the development of a centrally organised platform?

Yes. Generators routinely undergo maintenance outages or suffer unplanned failures, and DSUs routinely gain and lose customers, or find that their capabilities are changing. Secondary trading is an important risk management tool to manage such events, so we should expect frequent trades.

Furthermore, development of a central trading platform need not be particularly expensive. A relatively simple facility may suffice for the early years, with a more sophisticated platform only being developed if and when it proves necessary.

III. What limits should be placed on secondary trading timeframes, including: the timing of secondary trade execution – how soon after the auction should they be allowed, and how late in relation to real time delivery should they be allowed; and the length of the Reliability Option contract which can be traded?

The arguments in the discussion paper are persuasive: to maximise security of supply, competition, and efficiency, secondary trading should be allowed as soon as practicable after the auction.

Secondary trading, or something akin to it, should also be allowed for a limited period after delivery. This is important for market participants who work with aggregations of multiple small resources.

This is because there are scale advantages to such portfolios: it is much more cost-effective to design a single large portfolio to deliver reliable performance than multiple small portfolios that add up to the same number of MW in total.

Aggregators typically allow for the possibility of a customer failing to deliver by including spare capacity. In a simple "N-1" approach, they would allow sufficient spare capacity to cope with the largest customer failing to deliver. If they realise that a customer will fail to deliver, they will dispatch additional capacity to prevent a shortfall. The smaller the portfolio on which performance is assessed, the higher the proportion of spare capacity that will be needed, and hence the higher the cost.

An aggregator could benefit from this scale advantage – and hence offer capacity at lower cost – by offering all of their capacity in one huge DSU. However, this approach has downsides for the market: it would lead to an unnecessarily "lumpy" supply curve in the auction. It is preferable to allow the aggregator to offer the capacity in multiple smaller tranches, potentially at different price points, without having to forgo the scale advantage. This can be achieved in one of two ways:

1. By allowing ex-post secondary trading, so that the aggregator can move spare capacity from the DSU to which it happens to belong to a DSU that is suffering a shortfall. In the GB market design, this is achieved through "volume reallocation". Note that it is important that this reallocation can take place not only during scarcity events but also during any other required activations of the DSU, such as commissioning tests.[1]

2. By allowing the performance of multiple DSUs to be assessed in aggregate, without the need for explicit ex-post transfer of volumes.

For the ex-post secondary trading to fulfil this purpose, it must be allowed late enough that aggregators will know for certain how each DSU has performed in the relevant event, and can set the size of the trades on the basis of those results.

IV. Should the Capacity Market Delivery Body maintain the processes and capability to undertake pre-qualification throughout the year, and what service standards are required for processing new applications?

Yes. This is necessary to allow aggregators to maintain their portfolios. Aggregators have to do this so that they can maintain reliable performance when customers' capabilities change.

For example, a factory that is signed up as part of a DSU may install new equipment that is more efficient, and hence have less load available to curtail after the upgrade. Or they might go out of business, and hence no longer have any load to reduce. To maintain the ability to deliver the required level of capacity reliably, the aggregator must supplement or replace such customers with new customers.

It is important that such maintenance can be done in a timely manner – otherwise, reliability will be impaired for longer than necessary. Ideally, requests would be processed in a matter of days. Months would be unacceptable.

[1] To this end, there is a GB capacity market rule change under consideration by Ofgem (CP124, published 25 January 2016) to extend the volume reallocation facility to include "satisfactory performance days" and "DSR tests". In fact, the proposed rule takes an approach closer to the second option for those test events.

Note that this portfolio maintenance could be facilitated either by allowing new DSUs to be pre-qualified at any time, so that they can then be used in secondary trading, or more directly by allowing customers to be added to existing DSUs. In the latter case, some per-customer pre-qualification process may be needed.

4 Reliability option contract length

A) Principle of Longer Term Reliability Options: I. Do respondents agree that plant requiring significant investment should be able to avail of longer term Reliability Options? II. Do respondents agree that existing plant should be restricted to reliability options with a term of 1 year? III. Do respondents believe that longer term Reliability Options should only be available to new-build plant, or should also be available to existing plant where significant investment is being made to enhance or maintain its capability to provide capacity?

We agree with the discussion paper that there considerable down-sides for consumers from offering long-term contracts: doing so may not offer good value for money, undermines the signals for efficient entry and exit, and transfers volume risk to consumers.

However, we do not support the idea of discriminating between capacity providers by offering multi-year contracts for some types of capacity but not others.

The consultation paper quotes a European Commission working paper, and suggests that it shows that the Commission supports the idea of discriminatory contract lengths.[2] This is not the case. Neither the quote nor the rest of the paper argues in favour of discriminatory contract lengths. Rather, they set out the trade-off between short contracts, which send good price signals and minimise risk transfer, and longer contracts, which undermine these objectives but can reduce financing costs.

While the European Commission did accept the GB capacity market design through its state aid approval process, we note that this decision is being challenged in the European courts, with discriminatory contract durations being one of the key issues in the dispute.

We accept that longer contracts can reduce financing costs,[3] and so a lower cost outcome may be achievable by making longer-term revenue certainty available. However this should not be done in a way which distorts market outcomes by discriminating between different capacity providers.

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2 This error appears on pages 58, 60, and 66 of the consultation paper.

3 The quote on p.64 of the consultation paper: "Under current UK energy market conditions, project finance lenders are unlikely to take any market risk" arguably says more about the level of political intervention that has become commonplace in the GB electricity market than about any particular aspect of the market design. We hope that the I-SEM will be considered by investors to present a far lower level of political and regulatory risk.

Such distortion can be avoided either by:

1. Having only one length of capacity contract available for all capacity providers, with the length being a compromise between the objectives of responsiveness and revenue certainty.

2. Allowing a choice of contract lengths, so that proponents can obtain longer-term revenue certainty if they need it, but appropriately pricing the resulting risk transfer from the capacity provider to consumers. This should leave consumers indifferent to contract lengths. It could be achieved by adding a risk premium to the offer price when comparing offers in an auction. As a result, an offer that requires a long contract may not clear in an auction if the capacity requirement can be met using a slightly higher priced offer with a shorter duration.[4]

B) Classification of plant as new, upgrade or existing: I. Do respondents have a view on which approach should be used to classify capacity providers as "new", "upgrade" or "existing"? II. Do respondents prefer the approach of classifying providers as "new", "upgrade" or "existing"? Please indicate your view of the criteria, evidence and thresholds that should be used to inform this classification.

Taking one of the non-discriminatory approaches described above avoids the need for messy, subjective evaluations of "newness".

C) Maximum available Reliability Option lengths: I. Do respondents have a view on the appropriate maximum Reliability Option lengths that should be available to new-build and upgraded plant? II. How do respondents view the Reliability Option lengths in relation to the five generic frameworks set out in this section?

If only one length of contract is to be available, then we note that PJM has never offered contracts longer than 3 years, and yet has seen plenty of new build generation. Similarly, the Western Australian capacity market, although its rules allow for longer-term capacity contracts, has never issued anything other than a 1 year one. So 3 years would seem to be ample, and 1 year might suffice.[5]

If multiple contract lengths are to be available, then the risk transfer associated with longer contracts should be priced in such that consumers become indifferent to the contract length. Under this arrangement, longer contracts will tend to be less valuable, so it would not make sense for proponents to seek contracts of much longer duration than they need. In principle, this means there shouldn't be any need to set an upper bound on contract lengths. However, it might make sense to do so in order to limit the impact of inaccuracies in the pricing of the risk

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[4] The GB market rejected this approach because they could not find a method to value the risk transfer perfectly. We suggest that an approximate valuation would suffice to enable this flexibility. Otherwise, since discriminatory approaches should be ruled out, only a single contract length could be allowed.

[5] If prospective capacity providers require longer-term revenue certainty than is offered by the CRM itself, surely they could achieve this through a bilateral arrangement with a supplier or large energy consumer that will be liable to fund the CRM, and hence open to the idea of providing a hedge?

transfer. If a 15-year limit suffices in GB, with its extremely high political risks, then it should be ample here. We suspect that 10 years would suffice.

5 Stop-loss limits

We agree that it makes sense to define annual stop-loss limits as a multiple of the annual capacity fees. We believe that it is important to set the multiple at considerably more than 1x – otherwise, there will be no effective exit signal for unreliable capacity.

In general, given the choice between:

(a) a regime with strong penalties to incentivise reliable performance, and

(b) a regime in which penalties are capped at a relatively low level and instead there are extensive pre-qualification processes and tests and other bureaucratic hurdles, in an attempt to ensure that performance will be reliable despite the weak penalties,

… we would recommend the first approach. It is likely to be more effective, as well as simpler and cheaper to administer.

We would like to draw attention to a clever feature of the stop-loss regime under consideration for the GB capacity market: "soft" monthly penalty caps.[6] These ensure that there remains an incentive for a resource to deliver, even once the cap has been reached. Effectively, when the regime has run out of "sticks", it starts using "carrots" to incentivise performance.

6 Commissioning window and implementation agreements

H) Is a period of four years from the Auction Date to the start of the first Delivery Year appropriate?

Neither a T-4 nor a T-1 auction is ideal: as described in the consultation paper, the T-1 minimises volume risk, whereas the T-4 allows more technologies to compete. A hybrid approach – as taken by the UK and PJM – avoids the need to make such severe compromises. A large proportion of the required capacity is procured at T-4, but some is held back to later incremental auctions (in PJM's case), or to a single T-1 auction (in the UK).

Typically, the target volume to procure at T-4 is a bit less than the lower bound of the forecasts of the amount of capacity required. The actual amount procured can vary depending on price, due to the slope of the demand curve.

[6] These are described in §2.2.8 in Annex 2 of Department of Energy & Climate Change, *Consultation on reforms to the Capacity Market*, 15 October 2015. Note that the overall obligation trading and penalty regime described in that consultation document is absurdly complex, so it would not make sense to copy too much of it; it is just this element which seems quite useful.

To give participants more confidence that participation in the T-1 auction will be worthwhile, some additional volume can be held back and/or a guarantee can be given that at least a certain volume will be procured at T-1, regardless of what the forecasts then indicate is necessary.[7]

7 Administered scarcity pricing

A) *Which of the options do respondents prefer (and why) for the enduring level of the Full Administered Scarcity Price (FASP)? I. VoLL; II. EU Consistent (e.g. with GB); III. Euphemia Cap; or IV. Existing SEM PCAP*

VoLL seems appropriate, as it provides a very strong incentive for all participants to deliver under scarcity conditions, and is based on a measure of the inconvenience that scarcity events cause to customers.

B) *Do respondents agree with the definition of full load shedding (when Full ASP applies) as set out? If not please explain why, and your proposed alternative definition.*

The intention of scarcity pricing is to ensure that when customers' inconvenience is treated as the marginal resource for balancing the system, this is reflected in the marginal price. This avoids distortions, such as price reversals, which can occur if the system operator is able to take emergency actions which have the effect of reducing demand, but which are unpriced.

Hence, where involuntary load shedding is used reduce to system demand to bring it back into balance with supply, this should clearly trigger scarcity pricing. However, involuntary load shedding caused by a transmission or distribution failure should not.[8]

Similarly, low system voltages, if they are requested by the system operator as a means to reduce demand, should trigger scarcity pricing.[9] But if the voltage just happens to be low, not as the result of any deliberate act to lower it, then scarcity pricing would be inappropriate.

It is not obvious that there is any need for low system frequency to trigger scarcity pricing directly. System operators do not use frequency as a means to manage consumer demand. If a contingency event leads to a frequency excursion so

[7] In the UK, the amount held back from the T-4 auction is based on an assessment of the amount of cost-effective DSR that could participate at T-1, and the Government guarantees to procure at least 50% of this volume at T-1 – see §§45-46 of the public version of European Commission, *State aid SA.35980 (2014/N-2) – United Kingdom Electricity market reform – Capacity market*, 23 July 2014.

[8] If the network failure caused more load than generation to be disconnected, it would cause the system to have more supply online than needed to meet demand. Forcing energy prices to be high under such circumstances would be counterproductive.

[9] … although arguably not as high as VoLL, as the level of inconvenience caused to customers would not be as great as in the circumstances modelled for VoLL calculations. There may be no need for an explicit voltage-related scarcity pricing trigger, as the system operator would only take such an action if the operating reserve was already severely depleted, which itself would lead to a degree of scarcity pricing.

extreme that it exhausts the ancillary services meant to contain it (generation increase and voluntary load curtailment), then it will lead to involuntary load shedding, which would trigger scarcity pricing. Any other frequency deviations should not.

We agree that scarcity pricing should be based on what actually happens, rather than what is forecast. However, it would be helpful to provide warnings of anticipated scarcity. These would be useful on any timescale, but most effective if provided 30 minutes ahead of gate closure, so that participants have time to respond.

D) *If stakeholders consider that it is appropriate to set the Full ASP at a lower level for an introductory period they should also set out, how long that introductory period should be and why, or alternatively the principles that the SEM Committee should employ in deciding when to move from the introductory full ASP to the higher rate full ASP.*

While we favour a high value for FASP, we note that this will increase the distortion mentioned in §1 of this submission. This could have a serious effect on competition. To reduce the strength of this distortion, we recommend that a much lower value should be used for FASP during the interim period between I-SEM Go-live and when DSUs become able to participate in the energy markets. Once the distortion has been removed, FASP can be increased – either immediately or through some phased approach.

E) *If you favour a different level of Full ASP, either for an introductory period, or after any introductory period, please indicate the level and justify your response.*

We do not have a particular figure in mind. Any scarcity pricing will exacerbate the distortion during the interim period. The PCAP might be a sensible compromise for the interim period.

8 Transitional issues

A) *Which of the suggested options (annual auction, block auction, do nothing) do you prefer?*

The “do nothing” option is a misnomer. It would be better described as the “remove the existing capacity remuneration mechanism three years before its replacement is ready” option. Since it would provide no capacity remuneration at all for three years, this would be likely to put out of business all demand-side aggregators and possibly many other providers of peaking capacity. It should not be pursued.

We support the annual auction approach, as it is the most straightforward. While we can see the attraction of the block auction, the extra complexity – which would be challenging both for participants and for organisers – seems hard to justify for a once-only event.

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

Yours sincerely,

Paul

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