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SEM Consultation Paper SEM-15-104
Capacity Remuneration Mechanism – Detailed Design

Vayu welcomes the opportunity to comment on the SEM Committee's ("SEMC") consultation paper – SEM-15-104 on the detailed design of the Capacity Remuneration Mechanism ("CRM"), which examines various options for cross border participation, secondary capacity trading arrangements for Reliability Options ("ROs") and the structure of these ROs.

It is more and more apparent that decisions cannot be made in isolation on any aspect of the wholesale electricity market without assessing the impact of the decision on other areas. The Regulatory Authorities ("RAs") must continually consider avoiding any unintended adverse consequences of their decisions.

In general, Vayu believe that decisions arising from this consultation should be made taking full account of decisions and proposals made for DS3, Market Power and Market Rules workstream. There is significant cross-over between many of the issues and, potentially, unintended impacts arising from decisions made in these other workstreams. For example, proposals to manage Market Power may result in constraints in the level of offers made into the Balancing Market ("BM") that would have an impact on considerations for setting parameters for the Administered Scarcity Price ("ASP").

We are open to discussing our views in more detail and our comments on specific questions follow:

2.6.1 Interconnectors and Cross Border Capacity
A) Which of the approaches to the treatment of cross border capacity do you prefer and why? (For the Provider Led and Interconnector Led approach, please specify whether you prefer the "Performance based" or "Availability Based" variant).

The simple approaches of net-off from demand, Interconnector-led and FTR-led treatment of cross border capacity all have drawbacks that lead us to reject them as preferences. Netting-off demand does not provide any incentive for the provision of actual capacity. The Interconnector led approach only provides generating capacity if the Interconnector operator procures it and this would involve transmission operators participating in the capacity market(s) which we would view as extremely undesirable as it would lead to conflicts of interest between the Interconnector as transmission owner and procurer of generating capacity in the market.

While an FTR-led approach is attractive in theory, in practice the different time frames for FTRs (short term to encourage competition) and CRM contracts (longer term to incentivise the construction or retention of long-lived, high capital cost generating assets) makes this unworkable, in our view.

In addition, we also believe that it is important to future-proof any cross-border capacity arrangements for the situation where Ireland becomes connected to more than one external market. As the CRM is partly designed to incentivise construction of long-lived assets, and enter into long-term capacity contracts, this future-proofing provides a stable and more attractive environment for investors.

In general, we would prefer to see either the provider-led or hybrid approaches adopted. For the provider-led option we would prefer to see this based on actual performance to ensure that capacity is delivered to support the I-SEM system. We are assuming that other rules and arrangements (in particular BM/DAM rules and regulatory framework on market power) are in place to support this.

B) Should the de-rating of interconnectors be based on historic performance, or include forward modelling to project how its performance could change in the future?

De-rating of interconnectors should be based mainly on historic performance, although any technical or physical measures taken that would improve reliability or capacity should be taken account of as soon as practicable. Some form of weighting performance more heavily towards recent performance or applying this to any new or increased capacity would be acceptable.

C) If there is a preference for the "Interconnector led performance based" approach there will be a need to allocate total interconnector flows between specific interconnectors. Which of the specific approaches set out in 2.4.6 do you prefer? These approaches were:

- *Balance interconnector utilisation;*
- *Pro-rata to interconnector metered flow; and*
- *Complex power flow modelling*

We do not prefer the Interconnector led performance based approach as this could involve the Interconnector owners in procuring generating capacity in the market(s) which is undesirable. Transmission infrastructure owners participating in the energy or generating capacity markets can lead to conflicts of interest and the potential to restrict transmission access to competing generators.

D) If there is a preference for the "FTR led" approach, which of the specific approaches set out in 2.4.15 (net or gross) do you prefer for the allocation of non-day-ahead flows?

We do not prefer this approach as there is a mismatch between allocation of FTRs and CRM contracts that would make this an unattractive option for capacity providers.

E) If there is a preference for the "Performance based Provider Led" approach, which of the specific approaches set out in 2.4.25 do you prefer for the allocation of intra-day and balancing market trades?

- *As traded*
- *Pro rata to Reliability Option (in which case – do you prefer "gross" or "net")*
- *Ignore – all in Balancing Market*

Ignoring allocation of intra-day and balancing market trades and dealing with cross-border physical flows entirely in the balancing market would seem to be the simplest and most attractive approach. This assumes that the rules within the Balancing Markets in Ireland and GB and the commercial arrangements for Interconnector access and use are in place to facilitate this.

F) If there is a preference for the "Hybrid" approach:

- *Should this be paired with the "Delivery Based" or "Availability Based" provider led approach?*
- *Should Interconnector participation be mandated or voluntary?*

Our preference, if a hybrid approach is adopted, would be for this to be based on the 'Delivery Based' approach, with costs of non-performance allocated to those best equipped to manage the risks. Interconnector participation should be mandated to provide certainty and stability for investors in assets to provide capacity in I-SEM at times when it is required to alleviate system stress.

3.7.1 Secondary Trading

For this section, Vayu have adopted common option trading terminology to describe the trading of Reliability Options. Under this convention the TSO is the purchaser of Reliability Options, via the annual auctions, and pays capacity providers their fixed option premium. The providers of capacity are the sellers of ROs, receiving their fixed premiums in return for making difference payments above the RO strike price (and backing off this obligation with revenue from their physical generation plant). In the secondary market, a capacity provider, having sold an RO to the TSO, would commonly look to purchase an RO to cover its obligations when its own generating plant is on outage. We would suggest that it would facilitate discussions and consultations if this convention is adopted and maintained consistently.

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

We agree that direct secondary trading of Reliability Options should be permitted. It is fair and normal practice that sellers of ROs would have a need to purchase ROs from other parties to cover outages. Providers of ROs that did not find a market for their capacity in the auction should be able to re-appraise their prices and offer capacity into the secondary market and new entrant capacity providers should not be required to wait until the next auction to be able to sell their capacity in this way. It would seem excessive/intrusive to prohibit secondary trading of ROs *per se*, only secondary trading with a view to market manipulation.

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

We see no overriding need for a secondary platform to be developed for I-SEM go-live. We believe that it is probably better to let this evolve in response to participants needs, or to have 'basic' system without any mandatory requirement to trade on it. Creating a simple bulletin board as a centralised market-place for secondary traders of ROs might suffice (and would likely be created by market participants in any case if not made available).

Creating too prescriptive a system runs the risk that it does not get used if it fails to match participants' requirements (e.g. one that lists ROs by the week when participants planned outages are only for days). The secondary market for ROs is likely to have limited liquidity because of the relatively small number of participants and a bilateral approach to trading, at least initially, should be sufficient (provided that there is adequate regulatory oversight of the market to limit any anti-competitive behaviour).

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

We believe that back-to-back trading to lay-off exposure to difference payments should be permitted. It is difficult to see how this can be avoided as it would be relatively normal for generators to purchase some form of insurance product against plant failure. There will likely be some price/market efficiency benefits to allow providers to mutualise some of their risks in this way.

It is difficult to see any great advantage to customers and the market by prohibiting or constraining secondary trading, other than, perhaps, some potential improvement in price transparency. However there might be additional concerns in the situation where a portfolio owner of plant had a major share of capacity and was not releasing 'spare' capacity into the secondary market for others to purchase. Otherwise, constraining RO providers in their ability to manage or lay-off their risks is likely to increase the price of ROs sold in the annual auctions to the detriment of consumers.

Concerns over difficulties in exiting the market caused by the back-to-back approach can be handled by having assignment clauses in the contract for sale of the original RO to the TSO. Assignment of the contract could be made to a third-party that has qualified capacity with the TSO's consent, such consent not to be unreasonably withheld, when a participant wished to exit the market.

D) With respect to the creation of a centralised Reliability Option secondary market platform:
I. Is there likely to be sufficient demand for secondary trading to justify the cost of the development of a centrally organised platform;

We do not believe that, initially at least, there will be a sufficiently large number of participants in the secondary market to create liquidity and justify the costs of development of such a platform. A simple, low cost bulletin board should be sufficient in the first instance for market participants to advertise their requirements for trade.

II. Do respondents think that capacity providers should be allowed to acquire Reliability Option volume in excess of their de-rated capacity (plus the tolerance margin), and if yes, how the limit on Reliability Option volume for the net primary and secondary volume should be structured?

It makes sense for the Capacity Mechanism Delivery Body ("CMDB") to purchase annual capacity up to the de-rated capacity of individual generating plant to provide for security across the system. However, individual plant failure is more of a binary situation, with a 95% reliable plant delivering 100% of its name plate output on 95% of days and zero output on 5% of days (as a broad simplification). Generating plant should, therefore, be able to sell up to its nameplate capacity in the secondary market and, indeed, it is likely that this capacity representing the difference between nameplate and de-rated capacity would form the most reliable source of capacity to back secondary market ROs.

Prohibiting sales of this capacity (the capacity between the de-rated and nameplate levels or the 5% in our example above) would likely increase the level of risk to participants and, as a result, the price of ROs in the annual auctions. Selling significantly beyond nameplate capacity (or purchasing above this level in the secondary market) would be speculative, unlikely to contribute to system security and should probably be restricted given the limited depth of the physical capacity market.

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?

No limits should be placed on secondary trading timeframes, in our view, unless there is a clear justification for them. Any limits are likely to push risk back onto RO providers and, as a result, increase the price of ROs in the annual auctions. Market participants should be allowed to decide and agree on the secondary market products that most meet their requirements rather than being constrained to 'standard' products.

Secondary trading should be allowed immediately after auctions and allowed to run as close to delivery as possible to allow participants to fully manage their risks. Capacity providers should be able to trade ahead of full commissioning if they are prepared to take on the risk of physical performance (and can find a willing buyer for their ROs). There does not appear to be any great motivation for participants to undertake ex-post trading, but equally there are no overriding reasons to prohibit it; we, therefore, would be comfortable with this being allowed initially.

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?

The CMDB should maintain the processes and capability to undertake pre-qualifications throughout the year to support new entrants that might wish to join the secondary market within the year (and have shorter construction/delivery times than conventional new-build generation). Service standards should strike a sensible balance between timeliness and thoroughness in processing new applications and should, ideally, set a defined and limited timetable for completion of the process.

V. Should a secondary acquirer of a Reliability Option start from a zero position against each "stop-loss" limit, or should the loss transfer?

We believe that sellers of Reliability Options in the secondary market should start from a zero-position against each stop-loss limit. This would keep the pricing and terms of secondary trades comparable and transparent and assist liquidity in the secondary market. This would also keep the incentive on the secondary market seller of ROs to perform with their physical plant up to the (re-set) full stop-loss level.

Should the secondary market buyer and seller of an RO wish to limit liability through a transfer of stop-loss limit (and adjustment of the option fee) they can do so contractually between themselves. This would be analogous to the situation where subsidiary companies can be sold with or without associated tax-losses and the purchaser agrees to pay an additional amount above the company valuation to transfer those tax losses.

4.7.1 Detailed RO Design

Reliability option contract length questions

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?

Without access to longer-term Reliability Options there might not be sufficient incentive and security for investors in plant that requires significant investment to construct or refurbish. In order for the CRM to encourage this investment and secure capacity into the future, longer-term ROs are necessary.

II. Do respondents agree that existing plant should be restricted to reliability options with a term of 1 year?

If existing plant are allowed to bid for longer-term reliability options, there is a risk that consumers will be left funding assets into the future that should have exited the market. Restricting existing plant to one year ROs is more likely to reduce this risk of stranding.

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?

Longer-term ROs (10-15 years) should only be available to new-build plant. Existing plant should generally be restricted to annual ROs. Where significant investment is being made to enhance or maintain the capability of plant to provide capacity, a compromise of 3-5 years may be necessary to encourage this investment to take place and hedge future auction prices for consumers. A system where participants can elect the length of contract required, with maximums for new, upgraded and existing plant would appear to balance the various factors between reducing costs for consumers and providing stability for investors/financiers.

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"?

We believe that it is unavoidable that some element of judgement will be required for this classification and that it is the role of the RAs to exercise this judgment in a reasonable and sensible manner, consistent with the market objectives.

In most cases, the facts of the situation, coupled with published guidance on investment thresholds and other relevant factors, will make it clear which category capacity would fall under and make the process as objective and transparent as possible. In the exceptional cases, early engagement between capacity owners or developers and the RAs should avoid any issues of discrimination or incurring excessive costs before a decision is given.

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.

These classifications seem sensible and consistent with the lifecycle of long-lived, high capital cost assets as well as consistent with definitions in other markets. Criteria/thresholds and evidential requirements should be decided and published by the RAs. Existing plant could be fairly readily defined as plant that currently has connection capacity or has previously participated in the CRM (or the SEM). New plant could be defined where, say, 90% of the physical assets of the plant have been purchased and transported to the site for installation (for example, to allow for re-use of grid connection equipment).

Upgrades are harder to define, but some criteria could be given as guidance, for example where new equipment has been purchased and installed equal to 10-50% of the asset value of the existing plant or where an increase in capacity of >10% of existing generating capacity will result from upgrade work. Where generating plant does not fit these criteria, the RAs would make a decision (potentially supported by Independent expert engineers) and explain it with reference to the published guidance.

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?

For new-build plant, we would prefer the 'balanced' economic life approach, where the developer takes some risk on the level of annual capacity auctions later in the life of the plant. For current technology this would be around ten years, although this should be reviewed with changes in technology. The technological life approach would seem to be too subjective and potentially discriminatory.

For upgraded plant a maximum of half this life or five years would seem appropriate.

II. How do respondents view the Reliability Option lengths in relation to the five generic frameworks set out in this section?

The five generic frameworks are well described and selection between them is a necessary compromise between the different drivers listed in the following sections. We would resolve this compromise with the balanced economic life as striking a compromise between security for developers of new plant and the transfer of risk of stranded assets to consumers.

Stop-loss limits questions
D) Do respondents favour the I-SEM Capacity Year running from October to September, with annual stop loss limits applying over that I-SEM Capacity Year?

A capacity year running from October to September, capturing an entire Winter season and aligning with the Gas Market year would seem sensible and annual stop-loss limits should match this.

E) Do respondents believe that "per event/day" and "per month" limits are required in addition to the annual stop loss limit?

'Per month' stop loss limits would appear to us to be useful to reinstate the incentive to make plant perform following a period of unreliability. 'Per day' limits might weaken this incentive and 'per event' limits would be too difficult or subjective to define.

F) Which approach do respondents favour for the definition of the Per Day/event limit?

We do not prefer either of these options. 'Per day' limits would weaken the incentive to make plant perform. 'Per event' would be too difficult or subjective to define and this is not desirable for stability for long-term contracts.

G) Please provide views on the appropriate levels for the each of the proposed stop loss limits.

In theory, the premium required to write an option equals the expectation of loss in the event that the option is exercised. In that case, we believe that setting the stop loss limit equal to the annual capacity fee (1x) would put the capacity provider in a neutral position with little downside incentive to make its physical plant perform. We would prefer to see the annual stop-loss limit equal to double the option premium to give an incentive to make physical plant operate to back the difference payments from the option. This limit should be divided down into monthly limits with some degree of weighting toward demand to reflect the greater risks of system stress over winter.

Commissioning Window and Implementation Agreements questions

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

We believe that four years from Auction Date to the start of first Delivery Year seems quite long, particularly with an extended long-stop date beyond that. Three years would seem a more reasonable time to construct a CCGT or wind capacity that has already obtained planning consent.

I) Does setting the Long Stop Date at 18 months after the start of the first Delivery Year strike the correct balance between the costs incurred by the market and the ability for delayed or longer-running capacity projects to be completed?

We take the view, again, that 18 months seems quite long for the long-stop date. Generating plant in this situation will be deterring other potential new entrants from the market and possibly the closure of existing capacity that expects the delayed project to start. It is desirable to keep the long-stop date as short as possible, while still giving sufficient time to resolve construction/commissioning issues. A period of one year would seem to strike a better balance.

J) Are the proposed milestones reasonable?

We believe that the proposed milestones seem reasonable in the context of developing conventional thermal (particularly CCGT) plant. Consideration should be given to alternative milestones for different or emerging technologies.

K) Are there any other milestones, especially prior to Substantial Financial Commitment, which could be used to add security to the delivery of new capacity?

There are other milestones that could be used, some of which might be technology dependent, to add security to the delivery of the capacity. In advance of Substantial Financial Commitment (as detailed in the consultation), placing of pre-construction contracts such as options on turbines might be useful as a milestone and indication of project commitment. The first milestone of 'securing all necessary consents' could be sub-divided into the securing of some of the more important individual consents if required.

L) What proportion of the contracted capacity is appropriate to use to identify Substantial Completion?

The 90% proportion of contracted capacity, as detailed in the consultation and consistent with the GB market, seems appropriate in our view.

M) Is six-monthly reporting appropriate?

We believe that quarterly or even monthly reporting against the project plan would be preferable, in order to gain early insight into any project delays or problems (and proposed remedies). This should not be an unnecessary burden on project developers as they will likely be providing this information for internal management and financiers in any event.

N) Do any (or all) of the reports need to be independently verified?

With more frequent reporting, it would not seem necessary to independently verify all reports (particularly if these were for external financiers as well as internal management). Independent verification could be reserved for six-monthly or annual reporting or to ensure that reported milestones have been met. Maintaining a right of audit and the option to independently verify reports would seem a useful addition to this.

O) Does 18 months provide sufficient time after the Auction Date to achieve Substantial Financial Commitment?

In our view, 18 months seems more than sufficient to us to achieve Substantial Financial Commitment and that one year would be more appropriate. A project that takes more than one year to reach this milestone may have significant underlying issues and may be at greater risk of failing to deliver its capacity to back the RO it has sold.

P) Is it appropriate to terminate a Reliability Option for failure to achieve Substantial Financial Commitment?

We believe it would be appropriate to terminate an RO in these circumstances. Failure to achieve Substantial Financial Commitment within the timescales would be an early indication of a project that has significantly reduced chances of meeting its commissioning target. Taking this early action would allow increased time to remedy any projected shortfall in capacity by inviting other new-entrant developers to enter the next capacity auction.

It may be appropriate to provide a small amount of additional time where there is strong evidence that Substantial Financial Commitment is close to being achieved or there are valid reasons for a small delay. However, the capacity procurement body should, at least, have the option to terminate the RO in these circumstances.

Q) Should failure to achieve any other milestones (within a suitable window) trigger termination of the Reliability Option?

Yes, similarly to the failure to achieve Substantial Financial Commitment in (P), the capacity procurer should at least have the option to terminate in these circumstances.

R) Is it appropriate to partially terminate a Reliability Option if it can achieve 'Minimum Completion? What level should be set for Minimum Completion?

We believe that a level of 50% minimum completion, as per the GB capacity market for consistency, seems reasonable as standard. For certain technologies and circumstances, it might be useful to have a different level (e.g. a CCGT plant where one GT and the ST are commissioned, but one GT is inoperable) if pre-agreed.

S) If a Reliability Option is terminated under the terms of the Implementation Agreement, should this project be 'sterilised' for a period of time following the termination and be unable to participate in capacity auctions?

We do not believe that projects should be 'sterilised' in this way and that they should be allowed in the subsequent annual auctions, with some consideration given to change in ownership provisions to allow another developer to step in and 'rescue' a failing project. 'Sterilisation' of a project and its capacity is only likely to increase RO auction prices and disadvantage consumers as it increases developer risk. Loss of the long-term RO contract and the associated performance bonds would seem to be a sufficient penalty for non-performance.

T) Should the I-SEM consider terminating Reliability Options if the information submitted as part of the qualification process is discovered to be false or mis-leading?

We believe that the capacity procurer should consider terminating the contract for Reliability Options in these circumstances; this would be in line with normal practice in commercial contracts and government procurement. As a minimum, the capacity purchaser should have the sole option to terminate in these circumstances.

U) Do respondents agree that the level of the performance bond should be based on a pre-estimate of the cost to the market of non-delivery of contracted capacity?

We agree with the principle that it would be appropriate for the performance bonds to compensate consumers for expected losses in the event of non-delivery of capacity. However, this should be tempered by recognition of a disincentive to enter the market and the creation of an additional project cost for the performance bonds that will be passed on to consumers if the magnitude of these performance bonds is too large.

V) Do respondents agree with the principle that the level of performance bond should rise over time, reflecting increased costs to the market? If not, what alternative principle should be used and why?

We agree that as the consequences of failure to perform escalate over time, the incentive to deliver should become sharper and that the level of the performance bond should rise over time.

W) At what level in €/MW does the performance bond create a serious barrier to entry? Does this differ for small vs large plant or for different technologies?

This is likely to differ for different technologies and between small and large plants, with larger developers likely to be better equipped with the resources to shoulder larger performance bonds. The level in €/MW where this becomes a serious barrier to entry will differ with scale and technology and also changes in the market for capacity. The level should be set with reference to project financial models and periodically reviewed or potentially negotiated with capacity providers in advance of the auction.

X) Do respondents agree with the principle that use of a fixed €/MW level for all participants, regardless of size, to set the size of the performance bond does not fully capture the costs and risks to the I-SEM and that a more complex approach is needed? Do participants have an alternative preferred method for handling the greater risks to the I-SEM created by larger new capacity projects?

We tend to agree that a slightly more complex approach than a fixed €/MW for all participants is required to set the size of the performance bond and that this is necessary to capture the costs and risks to the I-SEM of different project sizes and technologies. For handling larger projects that create greater risks, we would suggest more stringent pre-qualification requirements (e.g. on the financial capability of developer, track record of developer, associated subcontractors and proposed technology or equipment manufacturer).

Other alternatives to handling these risks might include step-in rights for the capacity procurer in the event that a project fails, preferential rights to purchase a project if it is put up for sale or right of approval over any purchaser where a project is sold.

Y) How should the level of the performance bond change over time? Should this have any link to the milestones?

As the consequences of failure to perform escalate over time, the incentive to deliver should become sharper. Developers should not be uncomfortable with a link between performance bond increases and meeting project milestones, certainly as an alternative to simple increases scaling with time.

Z) Do you consider that the Time To First Delivery (/Time to LSD) proposed here for the CRM should also apply equally to the delivery of System Services under the DS3 arrangements? If you consider that the time (s) should be different, on what basis / what rationale should they differ?

Not all projects applying for ROs will be providing system services under DS3 and vice-versa (and where they do, the magnitude of income from each source could be vastly different in any event). There does not appear to be an overriding requirement to apply the timescales equally.

5.5.1 Level of Administered Scarcity Price

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

Adopting a pure economic basis, VOLL would derive an answer that may be economically robust. However, the RAs should be mindful of the impact this may have on customers; essentially should they be forced to pay up to that price for the last units to 'keep the lights on'. Indeed, if different countries set VOLL in different ways, this could result in a race to the highest VOLL to keep the lights on at the expense of the neighbouring states.

In that case Option II or III are probably more pragmatic, although Option III may appear 'artificial' and subject to change for reasons that have no bearing on I-SEM.

The existing SEM PCAP has the advantage that it's a round number that is lower than the others. This would appeal to customers and suppliers wanting to avoid high price spikes, but does not provide opportunities to innovate. Vayu's preference as a retail supplier, representing Customers best interests, is to argue for option IV or one of the lower options to avoid potentially punitive price spikes with a severe impact on a stand-alone supply business.

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.

We agree with the definition of full load shedding and believe that this should be made on actual events rather than forecasts (to avoid high prices being triggered by a spurious forecast). We do not have strong views on level of voltage/frequency drop required to judge that load shedding has occurred, simply that these should be clear and objective and, if possible, consistent with Grid Code or System Operator Service standards.

Similarly for the duration of voltage/frequency drop, we believe this should be sufficient to be meaningful (i.e. several minutes rather than seconds, and requiring a call on Tertiary reserve rather than just Primary or Secondary).

C) Do respondents agree that virtual bidding removes any incentives on capacity providers to withhold power from the DAM or the IDM to sell in the BM? Do you agree that this applies regardless of what market power controls are placed on DAM, IDM and BM bids? Do you agree that this applies regardless of the level of the Full ASP? If you do not agree, please explain why.

In our view, this may possibly work with single generators; it is not clear if portfolio generators or vertically integrated players might not benefit by withholding part of their capacity and working to drive DAM prices higher.

We believe the RAs ought to re-visit and re-consider this in the light of different market players and in the context of market power rules in the BM that potentially limit how high BM price can rise in relation to ASP level.

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.

Please see our response to question A, above.

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.

Please see our response to question A, above.

F) Do respondents agree with the proposed approach of using a static approach to setting the piece-wise linear ASP function at the inception of the I-SEM, and if not why not? If yes, do you agree with the proposed approach of setting the piece wise linear equation as a function of the remaining MW of available operating reserve?

We agree with the static approach at the inception of I-SEM as it is simple and practical and transparent to market participants. The proposed approach based on remaining available operating reserve does not seem unreasonable.

G) What should the value of X in Figure 12 be?

We have no strong view on the level of X. However, consideration should be taken of where the highest offers are likely to be, given any constraints on offers imposed by Market Power mitigation measures. This would avoid a large step-change in price if, say, the highest offers are hundreds of €/MWh and X at 90% of VOLL = €10,000/MWh. If the system is in stress, BM prices should already be quite high to incentivise more generation offers and/or demand reduction.

H) How far in advance of the start of the Capacity Delivery Year should the piece-wise linear function be set. Does this need to be before the T-1 auctions?

Ideally this should be before the T-1 Auctions to inform bidders into the CRM. Publication should be far enough in advance of the start of the year to allow market participants to take physical or contractual action to manage the risks associated with the level of these parameters.

I) Do respondents think that any changes need to be made to the governance of the target operating reserve policy. If yes, what are these changes?

Target operating reserve policy is set by the System Operators on a common basis taking into consideration the physical state of the system, in particular the largest single generation input. We do not see any pressing reason at present to change this, provided this decision can be revisited at a later date if circumstances or emerging technology require it.

6.2.1 Transition Arrangements

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

We prefer Option 1 as it allows for competition and innovation to develop through the transition period. Option 3 is too volatile with a step-change in payments between the end of SEM and the transition period and again with the introduction of I-SEM CRM. Option 2 would tend to favour incumbents and lock out opportunities for new demand side and storage services during the transition period.

B) If you prefer the do-nothing auction, do you believe this should be accompanied by relatively low levels of Administered Scarcity Price?

We do not prefer the do-nothing approach.

C) Are there any other transitional issues respondents feel that we should take account of when implementing the CRM?

The transition time period is far enough in the future and long enough to allow the emergence of new demand-side and energy storage measures that could provide services to balance the system. Any option selected should not unduly disadvantage these measures or dis-incentivise their deployment and this should be taken account of when implementing the CRM.