I-SEM

Capacity Remuneration Detailed Design 2

(SEM-15-014)

If you have any questions in relation to our response, please don't hesitate to contact me at connor.powell@sse.com

Introduction

Thank you for giving SSE the opportunity to comment on I-SEM Capacity Remuneration Mechanism Design. SSE is a utility with customers and assets in both Ireland and Great Britain – we have operated under a number of different electricity trading and transmission arrangements. To secure energy for its Irish customers, SSE is involved in energy portfolio management, electricity generation and gas production. We have tried to reflect this experience in our response.

Our priorities for I-SEM design are system resilience, competitive markets and a decarbonised future. Our assets keep the lights on by being available to produce energy when required and flexible enough to respond to changes in demand/wind when they occur. Our retail business supplies around 800,000 customers securing long-term supplies and managing a range of market and non-market risks on their behalf.

Designing an enduring CRM is critical objective given that design choices could radically alter system resilience and energy affordability. Our response to this consultation covers each of the areas in the consultation paper – a summary of our key recommendations are included below.

Interconnector and Cross Border Capacity	• Capacity located outside I-SEM will contribute to satisfying the I-SEM Security Standard. The transfer capacity offered by interconnectors facilitates the use of non I-SEM capacity to meet that standard but does not inherently offer any additional security in a scarcity period (and may actually act to increase LOLP in periods). • Interconnection investment is dictated by the requirement to relieve congestion between (or within) bidding zones. **It is critical that the design of the CRM does not distort this – unlike excess generation capacity where risks and costs are borne privately, excess transfer capacity will directly impose costs on all-island customers.** • SSE would favour either a Hybrid Explicit Auction or FTR led approach. While a provider led approach is theoretically correct, given that the first auction is June 2017, it would appear to provide an enduring rather than initial approach.
Secondary Trading	• The SEM Committee decision on outturn availability creates an issue under the Reliability Option design. This needs to be addressed in the decision paper. • Given the high and increasing generation capacity concentration acknowledged by the SEM Committee in their Market Power paper, we would recommend the establishment of an **Optional Centralised Market.** There is value in establishing a centrally funded market place in advance of delivery – this can act as a catalyst for trade in a new market • Secondary trading is reallocation of risk. In does not change primary, fundamental risk – in scenarios where a secondary provider has taken a different view of the risk under the reliability option, this does not impact on capacity providers (whose interest is in auction integrity), consumers (who remain hedged, regardless) and the TSO (outage rates will not improve based on reallocation of risk). T**he RAs should not restrict**

	flexibility through things like de-rating, timeframes or standardised products - these are bespoke products, and a trade should not happen unless both parties believe it to be beneficial to them**.**
Detailed Reliability Option Design	• The SEM Committee should not be in the business of taking views (and risk) on behalf of consumers on the forward cost of debt, or future cost of equity. Imposing artificially low contract lengths effectively does this. **A contract of up to 15 years matches the term over which a project is typically assessed and financed.** • The level of Stop Loss limit sets the carrying cost for an option. By capping exposure at the payments received, the SEM Committee would be making a poor distributional choice **– that any speculators or under-cautious participants with physical capacity can take risks that are underwritten (for free) by suppliers.** • The adjusted GB approach to implementation and commissioning comes from the experience gained in two T-4 auctions with a similar design structure. **The RAs should take GB learning and apply it, where relevant, in Ireland** – long completion windows with multiple opportunities to apply exemptions and administrative delay will impose substantive costs on the system as a whole, and undermine auction integrity.
Level of Administered Scarcity Price	• Given that expectations of cash-out price will ultimately determine unit commitment and scheduling decisions, an EU consistent approach would be best. **The GB post 2018 cash out value would be most appropriate.** • The ASP should be linked to actual Balancing Market operation - actual dispatch (as in SEM-15-103). **Moving directly from the highest accepted offer to full ASP without a linear operating reserve function linking the two would represent a significant risk for both generators and TSO.** • If you allow exposure to ASP to be determined by technical offer data (as implied in SEM-15-014), you allow providers to hedge their exposure to partial ASP through submitted technical offer data. This creates an incentive to declare inflexibility.
Transitional Issues	• We are disappointed to see that the approach outlined by the RAs previously, representing a linear path between the SEM CRM and the I-SEM CRM clearing price has not been included as an option in the consultation. This approach would be simple, efficient, transparency and neatly tie together CRM closure in SEM to CRM delivery year in I-SEM. • We would prefer the combined block auction approach outlined in the consultation paper – this generates clearer signals, and still allows the CRM delivery body to fine tune their requirements over the transition to the first ‘real’ delivery year. **Block auctions are a true ‘least regret’ approach – conservative, but also generating clearer signals for participants**. In single auctions, a TSO without sufficient committed plant may find they have no option but to procure capacity through load shedding.

Interconnector and Cross Border Capacity

First Principles

Capacity located outside I-SEM will contribute to satisfying the I-SEM Security Standard. The transfer capacity offered by interconnectors facilitates the use of non I-SEM capacity to meet that standard but does not inherently offer any additional security in a scarcity period (and may actually act to increase LOLP in periods).

In the short run, scheduling, commitment and dispatch of surplus generation in bidding zones is dictated by price differentials across markets. In the long run, generation investment is determined by fundamentals – requirements for energy, capacity and ancillary services that translate into reasonable expectations of revenues. Interconnection investment is dictated by the requirement to relieve congestion between (or within) bidding zones. **It is critical that the design of the CRM does not distort these – unlike excess generation capacity where risks and costs are borne privately, excess transfer capacity will directly impose costs on all-island customers.**

Interconnector de-rating

Ex-post analysis of analysis using historical flows into I-SEM during stress events will inevitably produce de-rating that is incorrect. The paper notes that ex-post historical analysis of stress events would include BCOP, SEM Capacity Payments and Carbon Prices among other distortions. Each of these produces (or changes) a signal to use the interconnector, and each would inevitably need to be 'adjusted' on a forward looking basis in any ex-post analysis. The 'adjusted ex-post' figure used for de-rating would start to look a great deal like the ex-ante fundamental modelling approach, excluding impacts from signalled major plant entry, exit or outage and underlying commodity input prices.

SSE would recommend moving straight to ex-ante fundamental modelling approach combined with historical outage rates – while this will also be incorrect and produce a range of potential import scenarios, it will at least take into account most of the relevant fundamental data. For interconnectors, even more so than with investment products, past performance is not indicative of future results.

Quantifying Cross-Border Flows

The I-SEM HLD and CRM 1 decision paper both explicitly overcomplicate cross border participation in the CRM – the restriction on physical interconnection products and the subsequent decision to apply a split market reference price necessitate further compromise and complexity to meet EU requirements on cross-border participation. We do not understand the following RA statement:

"Applying this Reliability Option settlement for cross border capacity means that, irrespective of the overall approach to cross border capacity, we need to measure:

- *The quantity cross border participants sold in each of the Day Ahead, Intraday and Balancing markets; and*
- *The price that applied for each of those sales."*

This appears to suggest that the RAs are confident that they can effectively interpret and audit trading and ancillary service arrangements across multiple jurisdictions in order to settle I-SEM Reliability Options. SSE would suggest this is not feasible, and that lack of feasibility should inform the choice of approach to the treatment of cross border capacity.

Options for Treatment of Cross Border Capacity

Realistically, the choice of approach is going to be an attempt to select the 'least worst'. Our own assessment of the various options is detailed below:

Net off demand

- This will make State Aid approval challenging – it has not been considered an enduring solution in any approval by the European Commission to date.
- It will provide no investment signals to non I-SEM generators, while likely providing an incorrect investment signal to I-SEM generators.
- It does not interact with the Reliability Option mechanism, leaving suppliers with hedging that does not match their actual requirements.

The netting approach can be fairly easily dismissed on this basis.

Interconnector Led Approach

- I-SEM interconnectors[1] do not face 'private' risks in the same way that generators do. Cost structures and cost recovery for assets that are effectively underwritten by all island customers are very different and will inevitably distort the RO auction.
- An interconnector owner is providing a transmission line between different markets, not actual energy. Directing scarcity revenue toward a transmission line[2] doesn't resolve scarcity and doesn't provide any investment signal for SEM or non-SEM generation.
- As noted in the paper, both performance based and availability based approaches are complex, and in the case of the latter, discriminatory. Particularly in the case of an availability based approach, interconnectors would simply add to the missing money problem the I-SEM CRM attempts to address, free-riding on cross-border investments that improve system reliability rather than explicitly contracting for a reliable supply.
- Unlike a traditional capacity auction, interconnector free-riding would directly impose additional cost on those explicitly contracting for firm supply under the reliability option. Suppliers will face a shortfall in payments resulting from distorted investment signals.

An interconnector-led approach is not viable. The remaining approaches, which attempt to direct payments for firm supply to providers of firm supply, could be.

FTR Led Approach

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[1] All-island customers effectively provide an put option that covers any shortfalls on HVDC Moyle or EWIC

[2] Few people would seriously argue that the shallow transmission asset connecting a station to the grid should be rewarded for its contribution to system reliability at the peak or be exposed to penalties for failure to deliver energy during periods of system stress. The weak 'signal' generated could suggest that a second connection asset might marginally improve actual availability but it cannot fundamentally alter the performance of the generation asset required to deliver energy.

- Financial Transmission Rights still (ultimately) direct money to the interconnector owners, with additional expectations of revenue priced into valuations of the instruments offered in annual auctions.
- They are also referenced against DA markets only, which means that FTR holders will either be exposed to risks that they cannot manage (under the split market reference price design choice) or excluded from settlement against IDM/BM, in which case they have a competitive advantage over other participants in allocation.
- The design decision on discounting transmission losses against FTR payments mean that multi-annual products cannot be offered (or reliably valued) until annual TLAFs are published.

However FTRs do cover partial participation in one of the relevant markets – if you ensure that holders are exposed to BM exposure through the Reliability Option, they can either contract in underlying markets to manage that exposure, or discount their FTR valuation and place a premium on their CRM offer accordingly.

The consultation states that:

> *"For capacity auctions held a year in advance, it is possible that some holders of FTRs will exist; however, the FTRs will not cover the full interconnector capacity – as some will have been retained by the interconnectors for subsequent auctions."*

This is true, and we believe reflects fundamentals about the actual reliability that interconnectors can offer. Given uncertainty about actual flows (the contribution to or reduction of system demand an interconnector will make in a year), there is a limited proportion of capacity that can be released and accurately valued far in advance of delivery, hence IC owners retaining capacity for subsequent auctions. This stands in contrast to a generator unit located in the relevant market – they can take a more definitive view (subject to EFOR) as to what contribution they can make during stress periods.

Given the requirement for cross-border participation and the underlying settlement infrastructure associated with allocation of and settlement against FTRs, SSE believes that an FTR led approach would be preferable to, and more viable than, an Interconnector Led approach. Annual FTR holders can participate in annual auctions. Short term FTR holders can participate in secondary trading - both should be subject to exposure across DA and remaining flows and can value those exposures accordingly when participating in CRM and IC auctions.

Provider Led Approach

- A provider led approach allocates revenues accordingly – theoretically, money for reliability flows to providers of reliability subject to their performance.
- The difficulty with any provider led approach is translating theory into practice – different jurisdictions and governing law may make it difficult to enforce contract terms.

We believe that the de-rating approach detailed in the consultation paper by the RAs is robust. The consultation paper outlines two different approaches to allocation of flows – a performance based approach is required to ensure that non-I-SEM providers do not face weaker incentives than those faced by I-SEM providers. Exemptions from performance would inevitably lead to suppliers overpaying for under-provided capacity. **While a provider led approach is theoretically robust, it may prove too complex practically for go-live at I-SEM day one, especially given that the first auction is due to take place in just over 1 year.**

Hybrid Approach

Given the theoretical issues with the FTR approach and the practical issues with a provider led approach, a hybrid approach may be most suitable on I-SEM day 1. Revenue for reliability needs to be directed towards (+/-)MW providers, and the solution needs to simplify some of the cross-jurisdictional issues that arise when either capacity providers or cross-border transmission lines do not perform. The explicit auction hybrid approach outlined in the capacity paper could work, but the implicit auction model could not:

- In the case of the implicit auction model, it would allocate the share of revenue to cross-border transmission and actual capacity providers on the basis of regulatory determination rather than commercial negotiation and competitive pressure. **The implicit auction model does not meet state aid criteria.** The 'balance of trade' effectively discriminates against I-SEM generation, with the added complication of comprising EirGrid Group by exacerbating potential existing conflicts of interest.

- In the case of the explicit auction model, while an interconnector is bidding directly into the auction, it ensures that allocation of capacity revenue is subject to competitive pressure. The correct balance of obligation and revenue should sit with the correct parties through commercial negotiation – an interconnector provider can assess its risk appetite and likely availability. It can then contract with generators at a rate that reflects the requirement to

SSE would favour either a **Hybrid Explicit Auction** or **FTR led approach.** While a **provider led** approach is theoretically correct, given that the first auction is June 2017, it would appear to provide an enduring rather than initial approach.

Which of the approaches to the treatment of cross border capacity do you prefer and why?

SSE would favour either a **Hybrid Explicit Auction** or **FTR led approach.** A reciprocal **provider led** approach would work on an enduring basis, but is unlikely to work on a transitional basis.

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?

The de-rating approach needs to mirror that chosen for conventional capacity. The RAs cannot exclude historic performance, particularly given the two existing interconnection assets in SEM.

Is there 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?

We do not favour an interconnector led approach.

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 believe that post DA exposure should be valued by participants using FTR products to participate in the auction. Moving away from a performance basis for one participant is discriminatory.

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 – this allows holders to participate in the relevant physical markets to resolve any residual exposure

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

We do not believe the implicit auction model approach is viable. The explicit auction model approach must be on a performance basis, not an availability basis.

Secondary Trading

One general point we would initially note, is that the SEM Committee decision on outturn availability creates an issue under the Reliability Option design. Every single capacity provider in I-SEM will be forced to trade a 5 day product to cover a TSO outage at their connection assets. In an unconstrained market, trading an unconstrained product, trading to cover what is clearly a transmission constraint imposed by the TSO is a major inefficiency. This will inevitably lead to perverse distributional impacts every year which will not be resolved by secondary trading. This decision needs to be revisited under I-SEM.

Type of Secondary Trading

There is a clear requirement for secondary trading – a model in which capacity providers who hold options are unable to change their exposure to those options (except at an administratively set price) will result in a number of distortions:

- Plant operators will be left without a method of hedging their within-year outage exposure;
- Uncertain capacity (like non I-SEM participation through interconnectors) will be unable to offer additional short term insurance;
- In the case of closure, there will only be an administratively set price at which to exit the reliability obligation;

Both back to back and direct secondary trading resolve these issues, if properly designed. The paper states:

> *"The potential benefits listed above suggest that the I-SEM should include provision for direct secondary trading of Reliability Options. This direct secondary trading would not preclude financial trading of the rights and obligations arising from reliability options."*

We agree – direct trading clearly has benefits in terms of credit risk and market settlement, however, the RAs should not be seeking to preclude participants who wish to value and offer terms against the RO instrument without physical capacity being in place. This participation is excluded from the central auction mechanisms so has no impact on auction integrity but will open up participation to those without spare de-rated capacity or uncontracted plant.

Given the high and increasing generation capacity concentration acknowledged by the SEM Committee in their Market Power paper, we would recommend the establishment of **Optional Centralised Market.** There is value in establishing a centrally funded market place in advance of delivery – this can act as a catalyst for trade in a new market. It does not have to be a complex or expensive solution – this is not a market in which there is likely to be substantial volume of trade. To date in GB, a voice brokered solution has not yet been established by interdealer brokers for exactly this reason.

By making it optional, rather than mandatory, this allows for a wider range of participants to agree (and implement) terms outside of a standardised marketplace. Given the structure of a reliability option as a product, and the likely concentration of uncontracted MW within the portfolio of one participant, we do believe that mandatory centralisation will hinder, rather than develop liquidity. A dominant participant can simply remain unhedged, using the natural hedge provided by their physical portfolio, or agree on internal transfer prices for options.

Limits on Secondary Purchasing

Again, given market structure within I-SEM, we think that the RAs should take a flexible approach. The paper states:

"Although the certainty of plant availability will increase approaching delivery, the probability of forced outages will remain non-zero at all times of year*. In addition, whilst intermittent plant may be more predictable 5 days ahead of delivery, allowing plant of any technology to acquire Reliability Options up to its nameplate capacity or Maximum Export Capacity is likely to overstate its potential contribution to alleviating scarcity."*

This is true, but this is also not an issue that impact on capacity providers (whose interest is in auction integrity[3]), consumers (who remain hedged, regardless) and the TSO (outage rates will not improve based on reallocation of risk). The reallocation of risk is secondary – it simply shifts risk around, rather than changing it in any real way. Taking an extreme example – a generator on prolonged forced outage in winter trades on its obligation to a portfolio of wind generation at 70% of nameplate capacity[4] - consumer, original capacity provider or TSO do not lose as a result of the trade if the secondary capacity provider has overestimated its availability.

The primary capacity provider can take a view of the probability that it will be available in a given period – in the above example, that probability is 0. The secondary capacity provider knows that the probability it will be available is >0 or the probability it will be called is limited otherwise it will not enter the trade. Nothing has fundamentally altered in terms of availability on given dates, but risk has been transferred to parties that are better able to

[3] Which is entirely unimpacted by secondary trading of obligations
[4] Far in excess of likely de-rating by the TSO

financially or operationally manage it. **Secondary trading doesn't impact on fundamental, primary risk – we believe that the de-rated capacity restriction should be removed for secondary trading.**

Limits on Secondary Trading Timeframes

In terms of product specification – given that a reliability option is a fairly bespoke product, we do not think that standardised products will be helpful. It is more than likely that standardised products will simply impose an unnecessary inefficiency[5] on trade and subsequently, settlement.

The two functions in which providers can trade ahead of commissioning and trade ex-post would be helpful. However, the former should be partial – participants who have committed to build plant should be able to trade secondary capacity to hedge late delivery of a project, but they should not be able to financially hedge the entirety of their 15 year obligation – they must pass on the new build contract (including the primary protections built in for consumer, TSO and auction participants) to the new capacity provider.

Given that providers will have the best information as to how their capacity is performing, or their project is progressing, we think that secondary trade execution should be opened as soon as possible after the auction – it is better for every participant that secondary risks are reallocated as soon as needed, and primary risks can be addressed as soon as possible. A plant that has committed to deliver in the following trading year, but finds itself consistently out of merit[6] should be able to signal and hedge that through a secondary market as soon as possible.

Stop Loss Limits

We have covered most of these points later in the consultation response under stop loss limits. Starting at a zero position against each stop loss is not viable – this is creating additional primary risk, rather than reallocating risk. No provider could justify contracting under terms that create an exposure that exceeds the option fee paid by many multiples. Transferring the stop-limit doesn't blunt incentives, given that the existing energy market incentives remain, and the secondary capacity provider will want to ensure that they are available for the exposure retained within the stop-loss limit[7].

> ***Do respondents agree that direct secondary trading of Reliability Options should be permitted?***
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> Yes – reallocation of risk on the basis of updated information is clearly beneficial for consumers, providers and the TSO.

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[5] If I know my outage is planned for 9 days, I want to agree terms that cover the period, rather than trading with multiple providers to create a composite product that hedges my risk

[6] With the inframarginal rent assumptions placed in the auction now undermined, it is no longer financially viable at the capacity clearing price

[7] Again, taking a practical example, no secondary capacity provider is going to declare themselves unavailable after x periods of scarcity in which the reliability option is called – they still have an expectation of uncapped energy payments.

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

We would prefer a simple optional central platform to act as a catalyst for secondary trading activity.

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

Yes – this will take place within large portfolios anyway, through internal trades. Restricting this trading would discriminate against participants with smaller portfolios.

With respect to the creation of a centralised Reliability Option secondary market platform:

- ***Is there likely to be sufficient demand for secondary trading to justify the cost of the development of a centrally organised platform***

  This will not be a high volume product, but a simple central platform is clearly justified.

- ***Do respondents think that capacity providers should be allowed to require 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?***

  Yes – restricting secondary trading to primary de-rated volumes is not viable in a concentrated market.

- ***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?***

  Trading should be allowed as soon as possible after the auction, and volume reallocation through secondary trading should be allowed after physical delivery. Obligations and protections under new build contracts should remain intact if traded on to a new provider.

- ***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, the capability must be retained (it is unlikely that all new build qualification will neatly align with assessment of existing capacity anyway).

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

  The stop-loss limit should transfer – no participant could justify taking on a position exposure potentially X0 x the option fee.

Detailed Reliability Option Design

Reliability Option Length

A new project will need to be financed over a period that reflects the capital employed. While the paper assesses trade-offs which emphasise consumer preference for short contracts and provider preference for long contracts this is only partially true. If the SEM Committee on behalf of consumers chooses to contract for a short period, they do not resolve either:

- **Volume risk:** This is a function of TSO forecasting, the methodology for which has already been decided on. Over contracting will not impact consumers, unless you reach a period in which all capacity is contracted for multi-year periods and no auction takes place. It will only impact on existing capacity providers, who cannot tender for the volume of capacity already procured. Generation assets are steadily replaced over time – we don't think 'overcontracting' as defined by the RAs is a likely scenario.

- **Price risk:** This is double edged – by pushing down the contract length, you simply increase the risk associated with new build capacity. This will be reflected in their offers into the auction and therefore in the clearing price for capacity. Short-term contracts do not change the fundamentals of investing in a project; they simply impose a straight-jacket when it comes to financing a project. An investor has to make a choice based on the cost of debt and equity at a point in time – a one, or five year contract means fewer choices.

The SEM Committee should not be in the business of taking views (and risk) on behalf of consumers on the forward cost of debt, or future cost of equity. Imposing artificially low contract lengths effectively does this. **A contract of up to 15 years matches the term over which a project is typically assessed and financed.** If there is more optimum financing structure at a given point in time, this should be left to capacity providers to discover and offer through the auction.

Identifying New or Upgraded Plant

A series of cost thresholds for plant are more robust, although we would caution that in the case of certain plant, the upgrade threshold should not be binding. For example, in the case of a hydro plant carrying out a substantive refurbishment, it may have a spend per MW above the new build threshold. It shouldn't be precluded from a refurbishment contract simply on the basis of a different cost structure and expected revenue recovery profile.

Realistically, tangible facts and expert judgement will be difficult to apply evenly across providers. They will also require substantive resource commitment from the CRM Delivery Body which is not an efficient use of resource.

Option Fee Indexation

Capacity providers cannot be expected to reliably predict (or hedge) inflation after winning a contract. While, theoretically, they could price this as a risk to be included in the CRM bid, this has the disadvantage of reducing auction transparency, and being inaccurate. As the paper correctly states:

"Efficiency will be improved if the Reliability Option Fee is increased in line with an inflation index."

Stop Loss Limits

The stop loss limit is a critical part of CRM design. As the paper notes, it:

- Incentivises capacity providers to perform;
- Minimises shortfalls in difference payments;
- Minimises disincentives to make capacity available at DA.

We would also add that the level of Stop Loss limit sets the carrying cost for an option. By capping exposure at the payments received, the SEM Committee would be making a distributional choice – that all capacity is equally reliable after standard de-rating, regardless of actual experience. This means that speculators or under-cautious participants can take risks that are underwritten (at no additional cost) by suppliers. While the paper states that:

> ***"Not exposing capacity providers to excessive risk. Excess risk may either be priced into auction offers (which would add to customer bills) and/or deter investment (which would threaten system security)."***

This is an incorrect view – you want the auction to price risks associated with physical delivery. If participants do not price that risk, consumers will effectively be paying less in their option fees, but paying more through energy payments across the year (which reflect tight margins) and in socialised scarcity prices.

Even if the SEM Committee prevents the auction from pricing physical delivery risk, it cannot prevent the market from taking a view and pricing the reliability of contracted plant, and overall system margin across the year in normal operation. Some stop loss limit is required to cap liability, but that limit should tend toward 2x annual capacity option fees.

Monthly or per event caps are unnecessary – any calculation as to where scarcity may fall in a given year will inevitably be wrong. Incorrect caps will then lead to strange distributional effects, as generators and suppliers are under or over hedged in given periods. An annual cap is more appropriate.

SSE would favour:

- An annual stop loss limit set closer to 2x annual capacity fees;
- No monthly or per event caps;
- A stop-loss limit matched to the trading year[8].

Commissioning Windows

The commissioning windows for both DS3 and the CRM should match – if the DS3 decision paper has given a five year maximum length, we believe that the commissioning window must also match. The RAs propose a period of four years between Auction Date and Delivery

[8] Covering the full winter period

for the reliability option – we would agree, assuming that the five years specified in the DS3 commissioning window includes a 1 year delivery envelope.

The adjusted GB approach to commissioning windows detailed in DECC's autumn 2015 *"Consultation on Reforms to the Capacity Market"* comes from the experience in two T-4 auctions with a similar design structure. The RAs should take GB learnings and apply them to Ireland – long completion windows with multiple opportunities to apply exemptions and administrative delay will impose substantive costs on the system as a whole, and undermine auction integrity.

Implementation Agreement

Implementation Agreements with multiple milestones may be complex to monitor, but they are absolutely essential to maintain auction integrity and to avoid unnecessary costs being imposed on the system as a whole.

As noted in the section on commissioning windows, we would recommend that the adjusted GB approach to implementation detailed in DECC's autumn 2015 *"Consultation on Reforms to the Capacity Market"* comes from the experience in two T-4 auctions with a similar design structure. The RAs should take GB learnings and apply them to Ireland, in particular:

- Applying multiple, well defined milestones;
- Calling for additional margin at the point at which milestones are missed;
- Adequate assessment of progress reporting;
- Termination events triggered in the event of false/misleading information.

Once milestones are identified, the performance bond should incentivise commitment – we agree that the initial methodology should be based around cost to consumers as calculated through VOLL, but we think that a cost to capacity provider approach should be explored after go-live. The auction arrangements shouldn't create an artificial cliff at 400MW – we would suggest a linear function, given that the additional costs associated with failure of a large provider should be identified and resolved through well-defined milestones.

The paper notes that:

> *"An argument could be made that the level of the Performance Bond needs to be set at a lower level prior to Substantial Financial Completion as a project may seek to keep its costs to a minimum prior to this stage. Setting the Performance Bond at the full level need to compensate the market is most likely to act as a barrier to entry at this time. "*

We think that substantial reduction in the level of performance bond cannot be justified prior to Substantial Financial Completion, given typical lead times for capacity, and the damage to auction integrity[9] that can be inflicted by an uncommitted future provider.

> ***Do respondents agree that plant requiring significant investment should be able to avail of longer term Reliability Options?***

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[9] A 200MW unit will potentially be setting clearing prices for >7000MW of generation – if set at an artificially low level, it may force committed providers to consider closure, exacerbating an already tight system.

Yes.

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

Given that both existing and new are participating in the same auction, yes.

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?

Enhancements under DS3 may require significant investment – enhancing providers should have the option of a refurbishment contract.

Do respondents have a view on which approach should be used to classify capacity providers as new, upgrade or existing?

MW thresholds are consistent and straight-forward.

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?

MW thresholds are consistent and straight-forward.

Do respondents have a view on the appropriate maximum Reliability Option lengths that should be available to new-build and upgraded plant?

An upper limit of 15 years is preferred.

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

We prefer the generic economic life framework.

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?

Yes, the capacity year should cover a full winter period.

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

No. Scarcity can never be entirely accurately forecast. Per event and per month limits impose an arbitrary redistribution of risk across providers and suppliers.

Which approach do respondents favour for the definition of the per day/event limit?

We do not favour a per day/event limit.

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

A limit >1 is required. We would prefer a limit closer to 2.

Is a period of four years from the auction date to the start of the first delivery year appropriate?

Yes.

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?

Yes.

Are the proposed milestones reasonable?

Yes, we would favour the application of the nine milestones proposed in the paper.

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

No, this is something to be addressed through reporting and performance bonds.

What proportion of the contracted capacity is appropriate to use to identify substantial completion?

As in GB, 50% is reasonable.

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

Yes.

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

Initially, the collateral requirement should increase. Ultimately, the 18 month long-stop date is the backstop termination date.

Is it appropriate to partially terminate a Reliability Option if it can achieve minimum completion? What level should be set for minimum completion?

Yes, minimum completion should align with the 50% threshold.

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?

Yes.

Should the I-SEM consider terminating reliability options if the information submitted as part of the qualification process is discovered to be false or misleading?

Yes.

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?

Yes, initially cost to consumer, with the enduring methodology looking at cost to providers (it is a more robust assessment of system costs)

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?

Yes, failure to achieve milestones should also trigger increases in posted performance bond.

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?

The performance bond is meant to partially cover the cost to the system of failure to commit and subsequently deliver capacity in advance of the contracted period. This cost does not vary across small or large plant, or for preferred technologies – to do so would skew participation[10].

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?

No. The size of the performance bond does not fully capture costs and risks to I-SEM of failure to deliver, but it fails to do so across all participants. Making the playing field less level will skew participation and ultimately, lead to sub-optimal investment choices.

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

This should increase over time. Failure to achieve milestones should also trigger increases in posted performance bond.

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?

The approach should be consistent across CRM and DS3 products.

Level of Administered Scarcity Price

Defining Load Shedding

The definition outlined in the consultation paper, where an EirGrid Red Alert has been triggered by either significant system frequency/voltage deviations or involuntary consumer load shedding is appropriate. The key is defining a substantial system frequency or voltage deviation – this should be clearly defined within both the Grid Code and Balancing and Settlement Code.

Including projected load shedding is not appropriate – this is something that should be covered by the reduced operating reserve function.

Value of Lost Load

[10] As seen in GB where regulatory incentives have resulted in specific size of unit participating in the auction

Given that expectations of cash-out price will ultimately determine unit commitment and scheduling decisions, an EU consistent approach would be best. **The GB post 2018 cash out value would be most appropriate.**

The EUPHEMIA price cap is a PCAP for a day-ahead market only – it does not reflect the various estimates of VOLL made across the EU for the purposes of designing balancing markets. Theoretically, in simultaneous stress periods, energy would consistently flow out of Ireland.

We are confused by a contradictory statement within the paper:

> *"Note that Administered Scarcity Pricing will not apply at times when there is sufficient available capacity, but it cannot start/ramp-up fast enough leading to a short term reduction in operating reserve – a frequent event."*

This statement appears to contradict SEM-15-103. In the period leading up to a load shedding event, whereby there is sufficient available total capacity but that capacity is not available within the timeframe required to avoid a reduction in operating reserve, a form of ASP will both apply (under SEM-15-103) and not apply (under SEM-15-014).

We would seek clarity on how ASP will be linked to actual Balancing Market operation - whether exposures will be determined by technical offer data (as implied in SEM-15-014) or actual dispatch (as in SEM-15-103). Moving directly from the highest accepted offer to full ASP without a linear operating reserve function linking the two would represent a significant risk for both generators and TSO.

To take an example – if a Moneypoint Unit was warming up but unable to start/ramp up fast enough to provide an offer, with the remainder of the Bid Offer Stack within the balancing period exhausted, pricing would likely reflect the strike price. Then, as operating reserve is reduced as under *Figure 12*, cash out prices would continue to reflect the strike price because there is sufficient available capacity (just not available to be activated in dispatch).

At the point at which load shedding occurs, prices would suddenly jump to full ASP. This would not be helpful for the TSO or capacity providers – there is no price signal reflecting how tight the system really is, until a Red Alert is triggered. We believe that administered scarcity should be triggered at the point at which available dispatch options in the Balancing Market are exhausted.

Obviously, if the TSO uses operating reserve while other options are available, capacity providers should not be penalised. If the TSO uses operating reserve as a last resort, this should trigger scarcity pricing, regardless of how many plant are 'technically' but not actually available for dispatch. We would be concerned that the note in SEM-15-014 incentivises inflexibility and allows capacity providers to hedge their exposure through technical offer data.

> ***Which of the options do respondents prefer (and why) for the enduring level of the Full Administered Scarcity Price (FASP)?***

EU consistent (consistent with GB, initially) – this reduces the potential for regulatory arbitrage and distortions to actual flows across member states in simultaneous stress events.

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 load shedding as set out.

Do respondents agree that virtual bidding removes any incentives on capacity providers to withhold power from the DAM or the IDM to sell into 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.

Yes, generators will be selling and buying power post DAM.

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.

It is not appropriate to set an introductory period – this will create opportunities for artificial arbitrage and potentially distortions to actual flows.

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.

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 proposed.

What should the figure of X% in Figure 12 be?

This should be Max 120% PIMB.

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?

This needs to be set in advance of the T-1 auctions.

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

We do not know what the current governance arrangements for target operating reserve policy are, but if they are directly linked to energy and capacity market settlement, changes should be published and consulted on, and align with auction dates.

Transitional Issues

Lead Times

We are disappointed to see that the approach outlined by the RAs previously, representing a linear path between the SEM CRM and the I-SEM CRM clearing price has not been included as an option in the consultation. This approach would be simple, efficient, transparency and neatly tie together CRM closure in SEM to CRM delivery year in I-SEM.

Of the approaches outlined in the consultation paper, we believe that separate auctions wouldn't generate the clarity needed by generators to take investment or closure decisions during the transition period. We would prefer the combined block auction approach outlined in the consultation paper – this generates clearer signals, and still allows the CRM delivery body to fine tune their requirements over the transition to the first 'real' delivery year. As the paper notes:

> *"It addresses the weakness in Option 1 by considering the capacity requirements for the complete transition period as part of the June 2017 Auction. This will look at the most economic procurement of capacity for the entire transition period – which may include procuring a plant for the entire period even if that plant is only required towards the end of the period."*

Block auctions are a true 'least regret' approach – conservative, but also generating clearer signals for participants. In single auctions, a TSO without sufficient committed plant may find they have no option but to procure capacity through load shedding.

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

A block auction

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

A do-nothing auction is not viable.

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

Not at present.