Electric Ireland Response:

Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism Consultation Paper

SEM-15-044

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Contents

1. RESPONDENTS DETAILS

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2. GENERAL COMMENTS

Electric Ireland welcomes the opportunity to respond to this Capacity Remuneration Mechanism (CRM) Consultation. Consistent with our response to the Markets Consultation, Electric Ireland views these consultation proposals from the perspective of a standalone supplier and as a representative of the customer. We are keen that the proposed I-SEM design including that of the CRM should operate effectively and achieve its aims, in particular for the CRM to satisfy an appropriate security standard at an efficient cost and provide efficient signals for market entry and exit as required. In our response we focus on those areas that particularly impact costs and outcomes for supplier businesses and customers.

It is also vital that the CRM works well with other components of the I-SEM design. There are clear interactions e.g. through the choice of market reference price for Reliability Options (RO) that directly affect liquidity but there are also important implications for the design and operation of I-SEM forwards or contracts for differences (CfDs) arising from the RO product design. In particular, in order to address the generator risk of having to pay out differences simultaneously under both ROs and CfDs, the capped differences approach should be used (as described in Section 3.1.4 of the Consultation Paper, and illustrated in Section 3.2.6 of this document) as excluding RO pay out periods from CfDs, as has been mentioned in industry fora, would be unacceptable to suppliers. These considerations will determine how feasible it is for suppliers to achieve an appropriate price hedge for their sales to customers.

More broadly, it is essential that the CRM is designed to complement the incentives provided by other market timeframes and initiatives such as:

- the imbalance price incentive on market participants to be balance responsible; and
- DS3 incentives on contracted assets to make available and deliver reserve.

In this context, all of the complexities presented as potential elements of the CRM may not be necessary if other components of the overall I-SEM / DS3 design achieve their objectives. Given that at this time, relevant decisions are forthcoming in all workstreams, market participants cannot yet make the combined holistic assessment of these I-SEM design components that is necessary. Consequently, as we suggested in our Markets Consultation response, it may be better to adopt an evolutionary rather than a big bang approach and not attempt to solve every problem through complexities within the CRM since the cost of getting it wrong may be greater than that of informed incremental change. Consequently, Electric Ireland have largely favoured the more straightforward of the CRM options presented which promote transparency, predictability, liquidity, and reduced costs and risks.

Overall, customers should expect to benefit from a material reduction in the cost of I-SEM capacity – though this may be balanced with other factors to mitigate the net impact for customers. It is important that the CRM is designed to achieve an efficient cost of capacity given the other value streams that are being developed for generators.

3. RESPONSE TO QUESTIONS

3.1 Section 2 – Capacity Requirement

The SEM Committee welcomes views on all aspects of this section, including:

3.1.1 Feedback on our minded to position to retain the all-island security standard of 8 hours LOLE

The I-SEM High Level Design envisages that the new market will deliver reduced capacity costs to the consumer. Although the lower security standard (of the two options) of 8 hours LOLE would deliver lower capacity costs to customers, it is worthwhile considering whether it would be advantageous to align quality of supply standards with that of GB from I-SEM Go-Live:

- the TSO estimates that the higher security standard would require an additional 220MW here valued at €14m(in 2016 ACPS prices). This cost is not overly burdensome, particularly if it results in the maintenance of a good quality of supply delivered efficiently for the benefit of customers

- the I-SEM target security standard (of 3 hours LOLE) would be aligned with that of GB & France and similar to that of the Netherlands (4 hours LOLE) providing an equivalent quality of supply for customers to our neighbours:

  - sets the target level of supply disruptions as no worse than our neighbours (while acknowledging that no disruptions are currently being experienced due to capacity surplus)

  - this may be a factor in attracting and maintaining foreign direct investment to Ireland and this may foster market growth through new customers and expansion by existing customers and while providing a clear signal of our intentions

  - although currently the SEM has an overall surplus of capacity (and arguably has been successful in attracting new capacity) it wasn't so long ago that urgent measures had to be taken to rapidly address a deficit: Emergency Peaker Generation (2003/04) and Capacity 2005 public competition. -Adopting a higher target standard combined with efficient entry and exit signals would act to maintain an appropriate economic level of capacity on the system and avoid the need for emergency action which may ultimately be more expensive for customers

  - A 3 hour security standard is likely to be required for regional harmonisation of capacity markets.

It is accepted that it is marginally more expensive for SEM / I-SEM to maintain a higher security standard due to the capacity being relatively more concentrated in a smaller number of units in the smaller system (TSO's estimate of an additional 220MW of capacity here valued at €14m using 2016 capacity prices). However Irish & Northern Irish customers may not accept that they are willing to cope with a higher level of supply disruptions than their neighbours.

As indicated in our general comments, customers should expect a significant reduction in the cost of I-SEM capacity. It is important that the CRM is designed to achieve an efficient cost of capacity given the other value streams that are being developed for generators. If there is not sufficient confidence, when taking other design aspects of the CRM into account, that significant reductions in capacity costs for customers will be achieved, then this move to a higher target standard should be delayed until required by regional harmonisation and suppliers will have to take the risk that the cost increases might not be able to be fully passed on at that stage.

3.1.2 Comments from respondents as to their preferred method of accounting for unreliability of capacity in determining the capacity requirement, along with reasons behind their preference.

Electric Ireland's preferred method of accounting for unreliability of capacity in determining the capacity requirement is the 'de-rating approach'.

This approach largely resolves the chicken and egg feature of the total requirement approach where:

- pre-auction, an assumption of capacity mix is used to determine the capacity requirement;
- in-auction, a different mix of capacity make economic bids;
- which changes the real capacity requirement that was an initial input to the process.

This is particularly a problem in the context of uncertainty over whether wind generators elect to participate (meaningfully) in the capacity auctions (should they be eligible).

In contrast the de-rating approach requires that each bidder's volume is adjusted for plant unreliability before the auction, and perhaps before the capacity requirement is announced.

3.1.3 Feedback on the options presented in relation to accounting for demand forecast uncertainty, along with rationale behind any position.

Potentially the stochastic modelling approach offers a robust method for dealing with demand forecast uncertainty since it enables assessment of both the impact and likelihood of a number of demand scenarios. This approach may be required for harmonisation of capacity markets but it is not widely used currently.

Electric Ireland are aware that this approach may be complex to implement at this stage and instead favour the "select optimal scenario using least regret costs" approach since this considers several potential scenarios and their impacts.

Electric Ireland suggests that investigations be carried out to determine whether the methodology can be enhanced to assign probabilities to the scenarios so that both the impact and the likelihood of the scenarios can be taken into account, although we accept that this might not be feasible due to the limited historical dataset.

Although the single average scenario approach has the benefit of simplicity, it carries a material risk that the security standard may not be met in a number of years. The worst case scenario approach guarantees that the security standard will be met but at the price of procuring excess capacity in most years and unnecessary costs being imposed on the customer.

Electric Ireland proposes that a sloping capacity requirement curve should be considered (as is used in GB and New England markets) as opposed to a single value, given the number of assumptions employed in its calculation, as this may allow procurement of additional economic capacity at low incremental cost depending on how competitive are the auction bids (or alternatively less capacity if not very competitive).

3.1.4 Feedback on our minded to position to base the capacity requirement for the CRM on a single capacity zone.

Electric Ireland agrees that the capacity requirement should be based on a single capacity zone because:

- it maximises the likelihood of a competitive result from the auctions (by concentrating all prospective capacity providers in a single zone / auction)
- it is consistent with a single I-SEM energy price zone
- it has the benefit of simplicity

3.1.5 Detail of any other considerations respondents felt that we should take account of when determining the capacity requirement for the CRM.

While supporting a single capacity zone on the grounds of competition and consistency we feel that an additional solution, either within or outside the CRM, is required to address the emerging deficit in Northern Ireland (while having a surplus in Ireland).

There is a significant risk that the Second North / South Tie-Line will be much later than the 2018 date given in the latest Generation Capacity Statement. This link is crucial to the I-SEM being operated as a single zone and the Generation Capacity Statement only considers capacity adequacy on an All-Island basis after its commissioning.

SONI's recent market process to procure additional capacity (which resulted in the 3 year life extension of some existing NI units) is further evidence of the need to procure capacity in NI. Further planned decommissioning in NI (due to the need to comply with environmental legislation) will exacerbate the problem.

Designing a CRM which delivers transparent, competitive, and efficient procurement of capacity on an all-island basis may not be sufficient if it results in load shedding of NI customers in the early years of the I-SEM or if less transparent and less competitive processes are required urgently to procure more NI capacity.

While there appears to be challenges involved in using the Locational Price Adjustment approach which would add complexity or in reviewing Generator TUoS charges to provide a better price signal, Electric Ireland urges the SEMC to pursue an appropriate solution for this substantive issue.

3.2 Section 3 - Product Design

The SEM Committee welcomes the views on all aspects of this section, including:

3.2.1 The approach to setting the reliability Option Strike Price:

3.2.1.1 Should we adopt the "floating" Strike Price approach, which is indexed to the spot oil or gas price?

Electric Ireland does not agree with adopting a floating strike price approach. Use of such an index (e.g. a spot oil / spot gas basket) introduces a basis risk for all generators, and creates a differential risk for generators using different fuel types e.g. coal burning plant. The mixture of an oil and gas index offers only partial mitigation of the risks involved for a gas generator and complicates hedging for both generators and suppliers. The role of the RO as a hedge against high prices for suppliers is undermined (especially if I-SEM CfDs exclude RO difference pay-out periods) as suppliers are then exposed to an element of fuel price risk and have to attempt to mitigate this by adding a premium for this risk to their customers tariffs (trying to hedge the fuel price risk for those specific periods may be difficult). In summary, basis risk is more difficult to manage with a floating strike price approach.

Consequently while a floating strike price may to some extent mitigate the generator risk of having to pay differences but not earning energy revenues due to adverse fuel price movements (since it was fixed at auction time), the mitigation is variable depending on fuel type and it would impose fuel price risk on suppliers who are less able to manage it and creates complexity in terms of hedging strategies for both suppliers and generators. In addition it significantly reduces the predictability of net energy revenues / costs.

The idea of a fixed strike price, which would be announced before an auction, is supported by Electric Ireland in that it offers more certainty to suppliers by capping high prices at a known level, with payback of difference payments, and making hedging strategies and, in turn, customer tariffs easier to construct. Forecasting of energy costs (net of difference payments) under fixed strike prices is likely to be easier than under the floating option. For these reasons, a fixed strike price may result in capacity bidders being less likely to require an additional risk premium.

Under the fixed price approach, generators should readily be able to hedge their particular fuel price risk on an annual basis. In the case of multi-year contracts consideration could be given to an indexed annual re-set process which should allow generator hedging of fuel price for the forthcoming year.

In section **Error! Reference source not found.** Electric Ireland proposes that the CRM be based n a tariff year (Oct-Sep) rather than on a calendar year and this would significantly reduce the generator risk under a fixed price approach (since winter comes first!).

3.2.1.2 How do we choose the reference unit? Should it be based on actual plant on the system or a hypothetical best new entrant (BNE) peaking unit as currently used for setting the Annual Capacity Payment Sum?

Ideally, Electric Ireland believes the reference unit should be a hypothetical efficient plant such as the best new entrant (BNE) peaking unit. Using the BNE would help to reinforce efficient exit signals.

However, the RO is intended to operate in two ways:

1. to allow efficient plant to recover missing money and be built and available; and
2. to incentivise available plant to participate in the reference market.

Selecting the BNE peaking plant as the reference plant may satisfy the first objective but frustrate the second (if inefficient peaking plant is successful in the auctions, this plant would be less likely to run when energy prices reach the efficient strike price, which would have the effect of eroding CRM revenues for inefficient plant.). In addition, the risk of not being able to run in order to offset difference payments may require inclusion of a risk premium within auction bids given the low strike price, which will lead to a higher CRM cost to customers.

Selecting the highest cost actual plant on the system (especially in the current overcapacity environment) may not support either objective if the strike price remains above market prices as there is no incentive to encourage available plant to participate in the energy market to prevent stress events from occurring.

Given that in the auctions, inefficient peaking plant would be likely to require greater missing money against any particular strike price (don't earn as much energy revenue), they would be less likely to clear in the auction and so exit signals would be provided via this route. Consequently, choosing the reference plant should be driven by the operational considerations of incentivising available plant to participate.

Electric Ireland believes that a balance needs to be struck in choosing the reference plant (between BNE and highest cost actual plant) so that strike prices are set at a realistic level which will encourage available plant to participate in the energy market(s).

3.2.1.3 Should we grandfather this reference unit where a multi-year RO is sold by new capacity?

Electric Ireland believes this reference unit should change over time to reflect changes in technology, and be used to recalculate strike prices to reflect prevailing forward fuel prices, FX rates, and CPI similarly to the current SEM arrangements for determining the BNE annually.

Strike prices clearly need to be re-based to reflect fuel price movements over the e.g. 15 year term (where within year price movements may be manageable) as well as associated FX movements. If CPI is applied to non-fuel cost elements, then some efficiency factors should also be applied to ensure that strike prices don't inflate away from market prices and fail to provide a continuing incentive for available plant to participate in the reference market.

An annual re-basing approach would promote the development of a simpler capacity market operationally-speaking since over time this would avoid the situation of having a number of long term contracts all with different strike prices and with incentives to engage in the reference market at different ("scarcity") price levels.

3.2.2 The Implementation of scarcity pricing in the I-SEM Balancing Market?

Electric Ireland questions the need for scarcity pricing in the I-SEM Balancing Market. Given parallel financial incentives for providing services/generation/capacity under DS3, to be balance responsible in ex-ante timeframes, opportunities to assist system balancing in the BM and CRM, is there a real need for scarcity pricing on top of, a yet to be definitively defined, single imbalance price? If the CRM and DS3 and the ETA markets are properly designed and their interactions properly managed the need for scarcity pricing should disappear altogether.

Electric Ireland does not support introducing scarcity pricing when we have no decision on the methodologies to be employed to determine the imbalance price and its likely level of sharpness. In our response to the ETA Markets Consultation we cautioned against designing an imbalance price that was too sharp beyond what was necessary to promote a response and so avoid imposing unnecessary costs on customers that could not be mitigated. Since it is likely that both participant and TSO behaviours will change, we recommended an evolutionary approach to imbalance price sharpness to allow informed decision-making about design in these changing circumstances. Scarcity pricing could be viewed in this context and only implemented later, in the light of experience, if required.

3.2.3 The choice of market reference price options from amongst the options presented and consistency with key objectives

Electric Ireland supports the use of the DAM as the source of the market reference price. As stated in the Consultation Paper the DAM is intended as the primary spot market in which the majority of energy will be traded in the I-SEM. It will be the most liquid and accessible market for the trading of physical positions by demand and generation alike. Using the DAM would significantly reduce basis risk for generators and suppliers and should further enhance liquidity in the DAM. Selection of the DAM maximises the likelihood that suppliers can achieve an appropriate hedge portfolio taking into account CfD's and RO's, whereas constructing a hedge portfolio under the other price options is likely to be much more difficult not least because of doubts about what CfDs generators would be willing to offer.

Reinforcing DAM liquidity through the choice of reference market ensures that the DAM accurately reflects all genuinely available capacity and produces a robust reference price. With CfDs then likely to be referenced to the DAM also, suppliers are more likely to be able to construct a reasonable hedge portfolio against DAM price exposure where most of their volume is likely to be traded thereby limiting overall price exposure and while leaving a residual exposure to volatile imbalance prices.

In addition the DAM reference price is likely to be more predictable than the BM allowing better forecasting of costs and revenues.

Even though a perceived downside of choosing the DAM as the reference market is that it doesn't reflect near real time system stress events, we believe that through the correct implementation of the CRM and design of other I-SEM incentives in the BM, IDM and DS3 that such scarcity issues can be properly addressed.

3.2.4 Whether the RO volume and/or the additional performance incentives should be load-following

Electric Ireland are not in favour of load following. Under the CRM, Suppliers will pay option fees to enter into a 1-way CfD with capacity providers to insure against stress events. If a load following obligation exists, capacity providers would be relieved of the obligation to pay difference payments where demand exceeds RO volumes and the suppliers' hedge would also be removed. The risk that RO holders would not be able to earn energy revenue (due to insufficient demand) to fund difference payments would be removed but suppliers would be exposed to the risk that high prices occur driven by outages (rather than by demand). This appears to skew the balance of risks in favour of the generators. Furthermore it is very unclear whether this change in the balance of risks will be fairly reflected in the auction bids and the consequent cost of capacity to the customer. It is arguably difficult to estimate how frequently and by how much would the obligation be scaled down for load following in advance for the purposes of construction an auction bid. Electric Ireland is of the view that this is not an efficient or fair way to manage this risk. Instead, if loading following is to be introduced to scale down RO obligations to meet load, so also should the option fees be appropriately scaled down to ensure that the customer does not pay for a service that cannot be delivered e.g. if the obligation is scaled down in a period, so also should the option fee for that week be scaled down by the same amount and the monies refunded to suppliers.

3.2.5 The requirement for, and design of additional performance incentives, including:

3.2.5.1 The form of additional incentives;

Given the above discussion about the design of appropriate incentives in different timeframes, Electric Ireland does not see any necessity for additional performance incentives to be included within the RO. Additional performance incentives may well end up duplicating rather than complementing other incentives in the other market timeframes or ancillary services schemes.

3.2.5.2 Scarcity based triggers for performance incentives

Additional incentives should not exist see section 2.2.5.1

3.2.5.3 Caps and floors on incentives;

Additional incentives should not exist see section 2.2.5.1

3.2.5.4 Performance incentives for renewables and DSUs;

Additional incentives should not exist see section 2.2.5.1 and section 2.3.2

3.2.5.5 Performance incentives during the pre-commissioning phase;

Electric Ireland believes that it should be possible to monitor the progress of new capacity against milestones to assess whether the capacity is on track to deliver before the delivery period starts and take early remedial action, including re-tender of that capacity possibly through secondary trading, if, the capacity provider fails to meet key development milestones.

3.2.6 Detail of any other considerations respondents feel that we should take account of when determining policy in relation to product design

There are important interactions between the design of the RO and consequences for the liquidity and design of I-SEM forwards.

We have already discussed how the choice of reference market could either reinforce the liquidity of the DAM or else split liquidity between the DAM and the BM. Where physical market liquidity is split between the DAM and the BM, generators may be less willing to offer forwards referenced to the DAM, where most of suppliers' volume is likely to be traded.

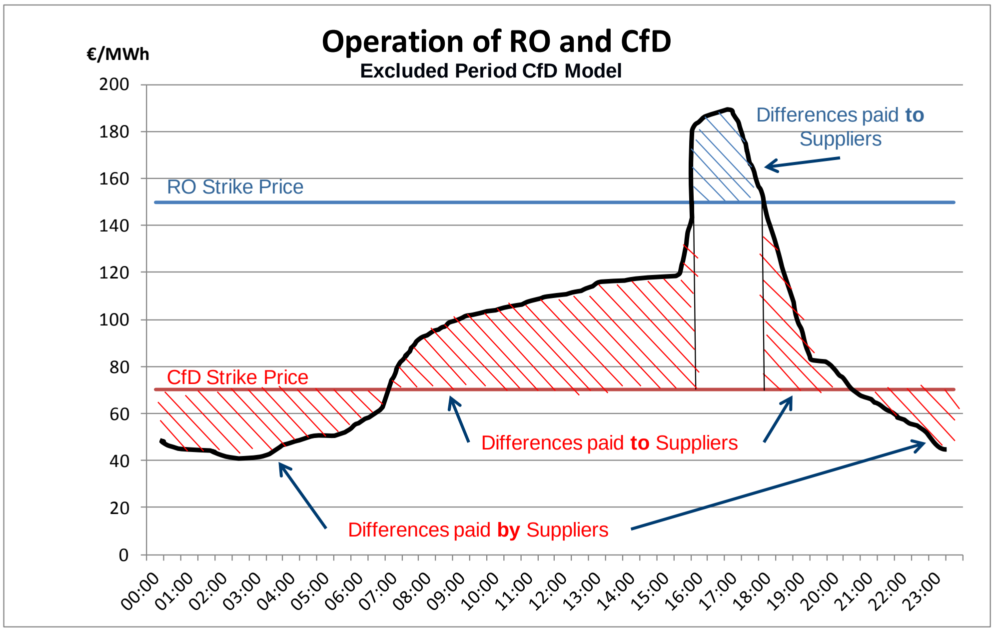
A further important interaction arises through the obligations to pay out differences under both ROs and I-SEM forwards (CfDs). While the design of the I-SEM forwards will be considered under the Forwards and Liquidity workstream, there are immediate consequences arising from the design of the RO and so are worth raising here.

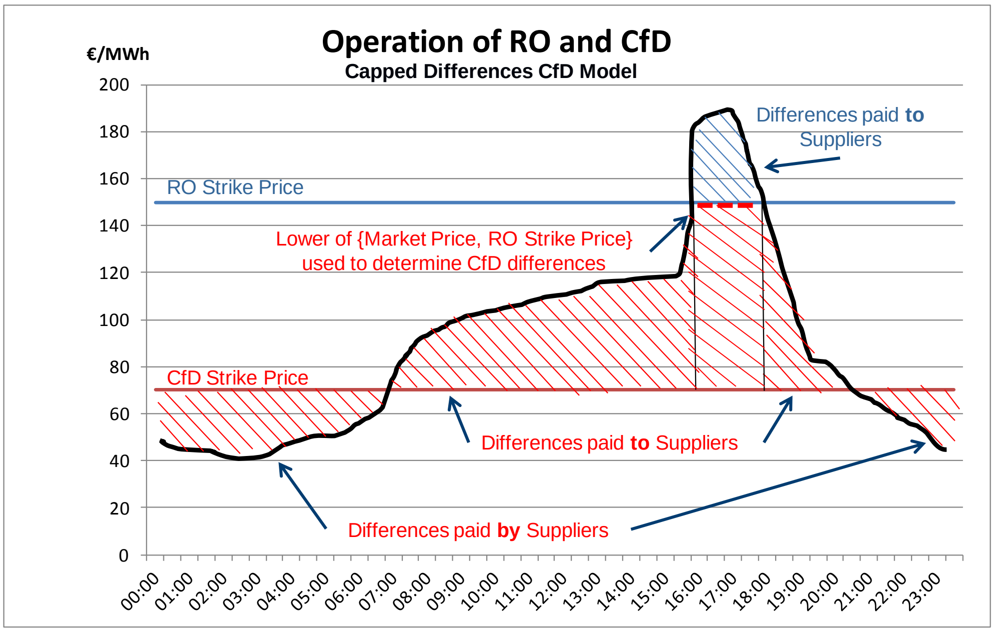
Should it be possible by design that the obligations to pay out differences under both instruments could coincide, then holders of ROs would be less willing to offer CfDs since their physical plant running in the energy markets could only back payment of differences under one instrument and so forward liquidity would suffer. Generators could take a view of the likelihood of RO difference payouts and reduce the level of CfDs they were willing to offer accordingly. However this approach would also eat into the volume of CfDs available in the market.

An alternative approach is to alter the design of the CfDs to avoid the double payment risk but would create a non-standard forward instrument that is immediately more difficult to value and which may be less attractive to market participants.

Two forms of alternative CfD design might be envisaged (depicted below):

1. CfDs which aren't valid in periods where RO difference payouts are made ("excluded periods CfD model");
2. CfDs which are valid in all periods but where the CfD difference payments are capped in those periods where RO difference payouts are also made ("capped differences CfD model") consistent with the worked example in Section 3.1.4 of the Consultation Paper;





The excluded periods model would be unacceptable to suppliers since it would act to fix energy prices in all periods other than those in which they were highest. The RO (if sufficient were available) would cap the prices, by definition, at a high level and the supplier would be exposed to prices in these periods up to the level of the RO strike price with no direct method of mitigation.

The capped differences model would be strongly preferable (but still subject to the disadvantages of non-standard products) since both instruments together, would provide suppliers with a hedge at the negotiated CfD price.

These examples demonstrate some of the impacts of RO and CfD product design on the ability of suppliers to hedge reasonably in the I-SEM. Electric Ireland believe that it is of the greatest importance, and a determinant of the success of the project, that the elements of the I-SEM design are crafted to enable suppliers (as well as generators) to readily construct an appropriate hedge portfolio for their physical positions.

3.3 Section 4 – Eligibility

The SEM Committee welcomes views on all aspects of this section, including:

3.3.1 The options presented in relation to the eligibility of plant supported through other mechanisms;

A number of conflicting objectives need to be addressed by the decision on eligibility of supported plant:

- that state aid guidelines on capacity markets are complied with including:

  - that all technologies should be able to participate;
  - that, where other considerations are equal, renewable technologies should be given preference; and
  - that exceptions can be made where capacity revenues would lead to overcompensation

- that policy convergence with neighbouring markets be supported so that eventual regional harmonisation of capacity markets is made easier rather than more difficult and that distortions of interconnector trading is minimised in the interim
- that changes to eligibility from current arrangements don't result in inappropriate cost recovery from one jurisdiction or from one class of customer

On balance, Electric Ireland supports "Option 3 - All Eligible" for the following reasons:

- most clearly supports the principle that all technologies should be able to participate and avoids the perception of bias against wind generation
  - wind generation will be de-rated to reflect their capacity credit;
  - the NI FIT CfD and REFIT 4 support mechanisms can be designed to reflect the I-SEM CRM policy decisions and avoid or minimise the possibility of future overcompensation;
- maintains legitimate claims of existing renewable generation to (some) capacity revenues and avoids further perceptions of regulatory risk
- avoids unfavourable cost recoveries either concentrated on NI customers (ROC to NI PSO) or switched from residential customers (under current profiled capacity charging) to business customers (flat PSO charging) which would result from other options where some parties were ineligible and reductions in capacity revenues were compensated by increased support payments
- affords a seamless transition for assets transitioning to a non-supported environment
- increases the likelihood of more ROs that may enable suppliers to achieve an appropriate hedge portfolio

This option doesn't satisfy the objective of closer convergence with GB given that supported plant is excluded from the GB capacity market however the need to achieve State Aid approval takes precedence.

The decision for intermittent generation about whether to participate in the CRM and bear the risk of difference payments geared by their de-rated volume or else earn additional revenues from high prices in energy markets is left to them. So there is no guarantee that there will be sufficient ROs to cover demand. It may be commercially beneficial for individual wind generators to operate via a wind aggregator which should act to reduce the risk of not being available during scarcity events.

3.3.2 The options for eligibility of demand side and storage providers

Option 3 is Electric Ireland's preferred position as it is likely to maximise demand side participation while physical performance can be underpinned through other incentives outside of CRM. Recently, in the SEM, performance monitoring of DSUs has been introduced, with a Working Group established, and this would seem to be an appropriate route for any further development of incentives that may be deemed necessary.

In our view Option 1 exacerbates the issue pointed out in 4.7.7. in that it exposes demand side participation to the risk of RO difference pay-outs without the benefit of receiving energy payments. In this scenario demand side participants may consider it a more prudent risk management strategy to not participate in CRM and not bid for reliability options.

While likely to deliver on the economic objectives for CRM, the challenges presented by Option 2 are two-fold, firstly the difficulty in establishing a value for foregone consumption and secondly the logistical difficulties in calculating and settling the market. Experience from other markets suggests that the implementation of Option 2 is not practicable from an I-SEM project timeline perspective

3.3.3 Supported plant:

See section 2.3.1

3.3.4 Do you have a view on the technology vs plant specific approaches to de-rating?

Electric Ireland believe that the best approach is a centralised approach where a guide is provided by the TSO's based on technology but allows flexibility for the participant to reflect realistic expectations of the individual plant's performance. This could take the form of a maximum value per technology published by the TSO and an appropriate lower or equal value submitted by the participant (similar to that of GB).

If the participant de-rating values are submitted e.g. during pre-qualification before final determination of the capacity requirement, then alignment of the values used ex-ante to determine the capacity requirement and the basis for the bids submitted in the auction by the participants can be ensured..

The development of a de-rating factor for aggregated DSUs based on generic technology factors will pose a challenge given the potential mix of demand-reduction, self generation and export arrangements which pertain across different DSUs - perhaps three different DSU technology classes are required

3.3.5 Do you have a view on the historic, projection or hybrid approaches to de-rating?

Due to the small sample size in the SEM, it may be appropriate to develop technology-specific de-rating factors from a wider database. If world-leading values were derived, this would fit with bidders being able to submit a lower value.

In the case of DSUs, the lack of historical data (of operation) would suggest the use of projection/modelling to determine appropriate de-rating factors. Irrespective of the approach, Electric Ireland would urge caution in direct comparisons with other jurisdictions where performance is likely to be heavily influenced by the particular DSM scheme rules. Hence careful interpretation will be required.

3.3.6 Do you have a view on grandfathering of de-rating factors?

De-rating should be reviewed regularly to ensure that they are still relevant.

3.3.7 Do you have a view on options presented with respect to the non-firm generation?

Generators which are connected to the grid but don't have firm access to the grid are typically thermal generators located behind some constraint usually wind, which gets preference.

Non-firm generators should definitely be allowed to participate as they represent a significant capacity in the market and could provide valuable capacity to the system when e.g. wind output was low during a system stress event (low wind likely being a contributory factor).

However there is no guarantee that they can provide capacity during system stress events. Electric Ireland believe that a normal de-rating guide should be published and the bidder can make a judgement about what level of risk they are willing to take in this regard.

3.3.8 What evidence should an aggregator be required to show physical backing?

Aggregators should be required to show evidence of physical backing, a suitable example of such evidence would be a letter of agreement between counterparties

3.3.9 Should there be a maximum size of unit that can bid into the RO auction via an aggregator, and if so what is that threshold?

The current SEM arrangements appear reasonable where a unit has capacity above 10MW has to operate on its own account and not via an aggregator.

3.3.10 Should there be a minimum size below which a capacity provider may not bid directly into the RO auction, and must bid via an aggregator? If so what is that threshold?

Electric Ireland recommend that a capacity provider below 2MW should bid in via an aggregator. The level should be set to alleviate administrative costs and time burden for the capacity administrator and also the capacity provider

3.3.11 What pre-qualification criteria should be applied?

Below is a list of prequalification criteria, this is not exhaustive list and different items may ne relevant to different types of capacity provider, the list of criteria should ensure against capacity provider not signing up who can't deliver:

- Credit cover worthiness
- Company authenticity
- Data to support de-rating
- Environmental compliance
- New and refurbished
- Planning consent
- Milestone plan including delivery date including implementation agreement
- Proof of Financial investment
- Technical characteristics of plant
- Financial information
- Status of connection agreement application
- Business model (for DSUs)

3.3.12 Detail of any other considerations respondents feel that we should take account of when determining policy in relation to eligibility.

n/a

3.4 Section 5 – Supplier Arrangements

The SEM Committee welcomes views on all aspects of this section, including:

3.4.1 Whether the recovery of CRM option fees from suppliers should be on a flat, or profiled basis

Electric Ireland is in favour of maintaining the current "SEM approach: profiles across all hours". In this regime, price signals exist to incentivise a change in customers behaviour not to operate in high demand periods and currently, where this price signal is passed on to customers, there is evidence to demonstrate adjustments in behaviour and moves of consumption away from these periods.

The GB approach of allocating costs across demand between 4pm – 7pm between November and February in theory offers the sharpest price signals in times of likely high demand However without quarterly-hourly metering there is no basis to reward these customers for any behavioural change resulting from price signals in their tariffs. Such customers don't see an itemised capacity charge in their bills. This situation is likely to persist until smart metering infrastructure is rolled out.

Electric Ireland is against sharpening the price signal to residential customers until such times as the infrastructure is in place to enable the residential customer to respond (e.g. home automation) and for measurement of the response at a customer level. For this reason Electric Ireland favours the SEM approach over the GB approach.

For these customers on fixed tariffs, both profile approaches impose a forecasting error risk to suppliers as there is a possibility that all of the capacity costs may not be recovered from customers if suppliers have incorrectly predicted price and volume in these periods. This risk is increased under the GB approach. Furthermore, under the GB approach, if customers leave a supplier mid-year suppliers will not have the ability to recoup the revenue to cover the annual costs incurred over the winter period.

The flat approach has the benefit of simplicity: very easy to predict and include in customer tariffs. However no price signal exists and this would represent a retrograde step from current arrangements since Business customers would lose the incentive to avoid high demand periods, which could lead to higher system demand peaks, increased system stress and ultimately more customer outages. The flat approach would also go against important principles enshrined in the smart metering initiative aimed at promoting positive behavioural changes in the demand side.

In section 5.4.2 of the Consultation Paper, it is proposed that high demand will be the primary driver of system stress events for many years to come. In the current environment of overcapacity, it is likely that generator forced outages and rapid loss of wind output have been strong contributory factors in recent system stress events. To the extent that overcapacity persists while wind penetration increases, this may increasingly be the case. Electric Ireland requests further analysis to support the proposition that high demand is, and will be for many years, the primary driver of system stress events and the consequent assertion that capacity costs should therefore be recovered from high demand periods.

Electric Ireland would highly recommend that the capacity charge is based on the Tariff year, October to September, instead of how it is currently calculated for the calendar year, January to December. This will ensure that capacity charges align with other charges in the market and that they are more accurately included in customers tariffs (as known values rather than forecasts). In addition this would have several other important benefits:

- if a fixed strike price is chosen, then assumptions about fuel prices made by capacity bidders are more likely to remain valid over the high demand winter period during the first half of the year (than under the calendar year where there is a greater risk of prices diverging by November / December) and where there is a greater tolerance for price divergence over the later lower demand summer months where market prices are less likely to breach the strike price - consequently this change may require a significantly lower risk premium for fuel price divergence within auction bids under the fixed strike price option;

- if any (annual) caps are deemed necessary on difference payments, then under a tariff year then these are more likely not to impact on the proper functioning of the ROs during mid-winter where as under the calendar year approach generators may not have the intended incentive to participate in the reference market and suppliers no hedge against high prices in November and December;

- it may conveniently align with the Q4 start of the I-SEM.

3.4.2 Whether the supplier credit cover arrangements for the I-SEM CRM should be broadly similar to those under the SEM, and whether/what credit cover arrangements should be introduced for capacity providers

Electric Ireland believe that level of credit cover in the market should be set at a level that would cover the maximum exposure to a defaulting party. Therefore, Electric Ireland are happy that suppliers' credit cover arrangements for the I-SEM CRM are similar to those under SEM. Under the new capacity arrangement, capacity providers will have to pay out reliability option difference payments and possibly penalty payments. As a result, credit cover arrangements should be introduced for capacity providers.

All efforts to achieve credit cover efficiencies should be made through consideration of netting off possibilities between different markets(e.g. DAM, IDM, BM and capacity especially if same settlement period(weekly) is used) and intercompany to prevent against excessive credit cover being required from participants.

3.4.3 Whether the costs of exchange rate variations (arising from differences in the €/£ exchange rate at the time capacity is procured and its subsequent delivery) should be borne by capacity providers or mutualised across the market?

There are two currencies that are supported within SEM: Ireland use the Euro, whilst Northern Ireland use the pound sterling. It is likely that support for dual currencies will continue in both the I-SEM energy and capacity markets. Consequently market participants will bid in to the CRM auctions and receive the clearing price in their local currency. Electric Ireland are happy that the exchange risk is borne by the market for the first year, however we have some concerns for long term capacity contracts as if this risk is not managed it could mean that customers are exposed to unnecessary costs.

We have given some thought to an approach, described below and in more detail in Appendix A, which we believe is non-discriminatory and treats capacity providers equally irrespective of jurisdiction while only requiring those elements of currency risk to be borne by the market as are appropriate. This approach would benefit from further examination to ensure that these principles are maintained. In short, this approach seeks to limit those currency risks to be borne by the market to those arising during each delivery year.

It is useful to consider what gives rise to this "long term" currency risk, mentioned but not defined in the Consultation Paper, and whether it is appropriate for it to be borne by the market.

"Adminstrative" currency risk could describe the risk arising from the CRM Settlement Body setting a supplier charge for a delivery year to reflect ROs that have been awarded based on a forecast of system demand and a forecast exchange rate (see Appendix A) - a risk materialises when the actual exchange rate through the year differs from the forecast rate and so an incorrect amount is recovered from suppliers - it is appropriate that the cost of this risk is borne by the market as a whole.

The other part of the risk, which might be described as "option fee" currency risk, could arise from currency price movements between the RO being awarded in the auction and a delivery years several years later. The Option Fee is intended to recompense capacity providers for the "missing money", the likely cost of difference payments, and for other risks arising from the specific design of the CRM. It is likely that major components of this are denominated in the local currency e.g.:

- the cost of capital (or the capacity provider makes a different decision with currency hedging as appropriate), and

- difference payments (both market reference prices and strike prices can be re-based to prevailing exchange rates, as discussed in the fuller description attached in Appendix A, preserving the frequency of difference payouts and the cost of difference payments resulting from exchange rate movements).

Consequently where supplier charging is targeted to recover the sterling option fee monies and euro option fee monies as awarded (and as potentially indexed), albeit using today's exchange rates, it is unclear whether there is a material "option fee" currency risk that needs to be recovered from any party. Neither does it appear that it would discriminate against any party due to any arbitrary choice of currency since most of the costs likely are denominated in the local currency.

In addition it is not clear whether a market operator such as EirGrid would be well placed to perform 15-year currency hedging even if it were clear what needed to be hedged and borne by the market and eventually customers.

A potential solution can be devised to limit the exchange rate risk that is managed by the market to a single year, similarly to the current SEM arrangements, based on the following principles (fuller description attached Appendix A):

- dual currency operations are supported in both CRM and energy markets with option fees, strike prices, and prices calculated in euro but published in sterling and euro according to published exchange rates; and
- the total forecast capacity pot to be recovered from suppliers for the forthcoming delivery year could be determined (as now) annually in advance using an annual exchange rate and taking into account all ROs already awarded for this delivery year either denominated in sterling or euro and either for a single year or for multiple years - and allocated to demand according to the chosen methodology.

3.5 Section 6 – Institutional Framework

The SEM Committee welcomes respondents' views on the issues raised in this section. In particular, the SEM Committee welcomes respondents' views on:

3.5.1 Are the above outlined governance arrangements suitable for implementation of the I-SEM capacity mechanism?

Electric Ireland is of the view that the governance arrangements for the capacity mechanism provide the right balance between the objective of stability, practicality and adaptability as described in Figure 6-3 of the CRM Detailed Design Consultation Paper. These arrangements will help achieve the following objectives:

- Promoting investment in capacity to ensure security of supply
- Facilitating the efficient operation and administration of the capacity market
- The proposed arrangements are practical and allow for implementation of the capacity mechanism as per the I-SEM project timelines
- Provide stability over the term of the capacity market building on the SEM framework arrangements

- Provides compatibility with the internal market by allowing for adaptation of codes and licences to cater for European internal market rules

3.5.2 Which options for contractual arrangements are the most appropriate as assessed against the listed criteria?

Electric Ireland supports the rules based model for contractual arrangements for the CRM. Given its alignment with the existing CRM in the SEM it will allow for simpler implementation of the new CRM as the existing arrangements would provide a strong basis for the new mechanism.

3.5.3 Are implementation agreements required for new entrants participating in the capacity auctions

Electric Ireland believes new entrants should be required to have implementation agreements in place to manage the period between a capacity provider having its bid accepted, and the relevant capacity coming into operation. Such implementation agreements when in place under tight capacity margins conditions, guard against project delays leading to a cost to society through higher than desired risk that customers will be disconnected.

4. APPENDIX A - POTENTIAL METHODOLOGY FOR DUAL CURRENCY SUPPORT IN THE CRM

Objective: Enable dual currency bidding into CRM euro-based auctions and either euro-denominated or sterling denominated ROs for successful bidders.

Auction Process:

- The fixed strike price is determined in euro and published
- The auction exchange rate is published [the day] before the auction and a sterling strike price is calculated
- Participants can submit bids in either euro or sterling
- All bids are converted to euro using the published exchange rate
- The auction is cleared determining the successful bidders and the clearing price in euro and, using the same exchange rate, its sterling equivalent
- Successful bidders are awarded ROs for a future year (e.g. 1 or more years ahead) denominated in euro or sterling depending on their jurisdiction / chosen currency with option fees derived from the clearing price

RO / Supplier Charge Operation:

- Holders of ROs receive option fees (e.g. monthly) and pay differences to the CRM Settlement Body if the market reference price exceeds their strike price – all prices / monies in their chosen currency (and, as now, market reference energy prices calculated in euro but published in both sterling and euro using a daily exchange rate)
- Capacity costs are recovered via charges to suppliers in their local currency calculated pro-rata to demand according to the selected allocation methodology and based on calculations [e.g. on a daily basis using metering data] with invoices rolled up into [e.g. weekly] billings (which may coincide with BM billing cycles)
- The forecast supplier charge capacity pot to be recovered for the forthcoming delivery year could be determined (as now) annually in advance using an annual exchange rate taking into account all ROs already awarded for the forthcoming delivery year either denominated in sterling or euro and either for a single year or for multiple years:
    - the annual exchange rate is required to adjust because the currency mix of the capacity ROs may not match that of the forecast energy consumption in the two jurisdictions for the delivery year

Rationale and Implications:

- Assuming Dual Currency participation in DA / ID / BM / IMBALANCE MARKETS is supported , participants in NI and the RoI can trade both energy and capacity in their local currency

[Perspective: retail revenue will (for the foreseeable future) be collected in Sterling in NI and Euro in the RoI so that dual currency operation is required at some point in the overall process by suppliers – consequently all market segments should be designed to support multiple currency participation as a more equitable proposition and to avoid discriminating against NI or RoI consumers]

  - Its unclear whether the impact of currency fluctuations from the auction until the point of determining the annual capacity pot doesn't need to be managed by the market, only during the delivery year of operation – since major cost items reflected in the option fee are likely to be denominated in the local currency e.g. the cost of capital and, under this proposal, where both market reference prices and strike prices are re-based to reflect prevailing exchange rates, the frequency of difference payments due to currency movements should be largely maintained (or at least limited to movements during the delivery year) and so there is little reason for the market to bear any currency "risk" arising from multi-year ROs

➔ consequently the market's currency risk in relation to supplier charging under this proposal is similar to the current SEM arrangements and could be managed in a similar way or alternatively recovered more straightforwardly through a tariff arrangement with annual reconciliations

- Depending on the approach to grandfathering strike prices for multi-year ROs, due to currency fluctuations over a [1 or more] year period the sterling and euro RO strike prices fixed at equivalent levels in the auction may diverge (when viewed using today's exchange rate conversion of the [DAM] euro price) creating the possibility of multiple RO strike prices in operation and reflecting "scarcity" at different levels
- Depending on the timing of option fee payments and receipts of supplier charges there may be a working capital requirement on the central body issuing ROs: option fees imply payment in advance (perhaps on a monthly basis) while supplier charges (if based on energy volumes consumed) imply payment in arrears (or perhaps payment on account with reconciliation in arrears) - the gains to be made from more frequent (e.g. weekly) CRM supplier charges in terms of lower credit requirements (and potential synergies with BM settlement) may well preferable to avoiding having additional reconciliations due to demand forecast errors - in practice, the 13-month global aggregation cycle will require demand resettlements between suppliers anyway.
- From a perspective of transition from the current SEM where suppliers pay in arrears for the CRM, bringing forward I-SEM supplier charge payments would require double payment from suppliers (and double receipts for generators) over a month or so, unless some transitional arrangement was applied where e.g. in the first year, 12 months supplier charges were collected over 11 months