ESB GWM Response: Integrated Single Electricity Market (I-SEM) Capacity Remuneration Mechanism Parameters Consultation Paper SEM-16-073

21st December 2016

Contents

EXECUTIVE SUMMARY

I-SEM aims to secure a highly reliable electricity supply in Ireland and Northern Ireland, which is essential to attract foreign direct investment and underpin lasting economic prosperity. The CRM parameters, together with the capacity requirement, are two of the most significant influences on the commercial and strategic decisions of all market participants under the new market arrangements. The approach to setting the CRM parameters is critical for I-SEM to achieve this aim.

ESB GWM's assessment of the Consultation (SEM-16-073) has identified a number of substantive issues that may undermine the achievement of the I-SEM objectives and therefore requires re-examination.

Three overarching observations are particularly notable to ESB GWM.

- The new wholesale electricity market arrangements consist of separate but interdependent markets for energy, capacity and ancillary services (DS3). This Consultation adds to our concerns expressed in response to the Offers in the I-SEM Balancing Market consultation (SEM-16-059). The SEM Committee's proposed definition of the fixed operating costs in this paper makes no provision for the recovery of investment costs, such as the return on capital or depreciation, or variable operating costs.

  The combination of these proposals in specific circumstances may restrict a generator's cost recovery below **long run** marginal cost. Generators who are unable to recover these costs in the balancing market or the capacity market would need prices to rise in the energy market to remain financially viable. ESB GWM believes this is a fundamental flaw and effectively amounts to the SEM Committee regulating the power market prices below cost.

- We welcome the recent stocktake exercise that concluded the baseline design of I-SEM is fit for purpose. Considering the above together with the potential unintended consequences we highlighted in our response to SEM-16-059 and that a number of key decisions are yet to be made we ask the SEM Committee to assess the market's integrity and internal consistency as these decisions are made and once the final design is complete.

- We reiterate the importance of a clear and comprehensive governance framework for the CRM, as mentioned in our response to the Capacity Requirement and De-rating Methodology consultation (SEM-16-051). Now the stocktake exercise is complete we ask the SEM Committee to produce that framework, ideally as part of the Capacity Market Code (CMC). The immediate priority is clarity on the timelines and processes for the first transitional auction in December 2017. Section 2.2 outlines what we consider are the essential components of that governance framework.

Auction parameters

ESB GWM considers the Best New Entrant (BNE) assumptions need some refinement to be fit for purpose for I-SEM. The applicable forced outage rate (FOR) should reflect the process set out in section 4.4.1 of the Capacity Requirement and De-rating Methodology decision (SEM-16-082a). The proposed adjustments to include RO difference payments and to shift from nameplate to de-rated capacity are suitable. Two further adjustments are worth considering. First, a higher hurdle rate may be appropriate for the BNE in I-SEM given the greater level of risk of operating in the market and the proposal that sunk investment costs are not recoverable after the period of the RO contract. Second, the BNE calculation should also reflect the higher credit and working capital requirements of the new market.

ESB GWM considers the auction price cap should be set at a higher of 2 the Net Cost of New Entry (Net CONE). A new build Capacity Provider in I-SEM faces a different set of risk and challenges to SEM in the form of sharp imbalance prices, Administered Scarcity Pricing (ASP), scheduling risk and the prospect of having to make difference payments up to the annual stop loss limit of 1.5 times the annual option fee.

ESB GWM considers there are three shortcomings with the calculation of Net Going Forward Cost that affect the determination of the Existing Capacity Price Cap.

- The proposed definition of the fixed operating costs in the Net Going Forward Cost formula makes no provision for the recovery of investment costs, such as the return on capital or depreciation, or variable operating costs. This creates a risk for existing generation owners and will potentially deter new investors that they may be unable to recover their costs given the market design.

  We question how the infra-marginal rent calculation will work in practice with the CRM Locational Issues decision (SEM-16-081), which opted for auction format option B, an additive approach. EirGrid, the competent authority on this subject, has previously calculated that purchasing 220 MW would be sufficient to move the effective security standard from 8 hours LOLE to three hours LOLE. This would reduce the likelihood of full or partial ASP reducing the infra-marginal rent Capacity Providers earn from the energy and ancillary services market while increasing the 'missing money' Capacity Providers would have to recover from the capacity market to justify continued operation.

- ESB GWM does not consider the Non-fuel Operating Costs are suitable to use in the Net Going Forward Cost formula without making two adjustments. The first is necessary to apportion Non-fuel Operating Costs that are held centrally within a portfolio, which means they are not allocated to specific stations or units. The remaining Non-fuel Operating Costs, which are often allocated to one unit for each station, an adjustment is needed to allocate these costs across the units at each station according to the running hours over the year. The SEM Committee indicates that it may choose to make adjustments to the historical data. ESB GWM would strongly oppose this if were done without further engagement with the industry.

- A degree of caution should be used in over relying on international benchmarks due to: the currencies these costs are presented in and the years in which those costs were reported; the analysis takes no account of other factors effecting costs such as plant age, unit availability and location; the difference in the design of the electricity markets and their associated rules; and the previously mentioned issues regarding SEM fixed operating cost data.

Basis on the information and analysis presented in the Consultation the choice of 50% of the Net CONE as the Existing Capacity Price Cap appears to have very little basis other than being a round portion of Net CONE.

ESB GWM favours Option A as the shape of the demand curve for the first transitional auction. A shallower demand curve is more appropriate until the TSOs can satisfactorily resolve the identified modelling issues with estimating the relationship between installed capacity, the number of hours of Loss of Load Expectation (LOLE), the Expected Energy Unserved (EEU) in MWh, and the cost of EEU to the consumer in €m p.a. when unserved energy is valued at Value of Lost Load (VoLL). Once these limitations are resolved it would be appropriate to move to a steeper demand curve akin to Option B.

Investment thresholds, termination fees and performance bonds

The approach to determine the substantial investment threshold of 50% of the BNE is appropriate for all Capacity Providers. Notwithstanding our views on the calculation of the BNE itself.

It is not appropriate to apply termination fees to existing Capacity Providers with above 50 MW of registered capacity as requirements to post credit and collateral and the Grid Code provide strong incentives to be operational in the years leading up to the delivery year and in the delivery year. It is less clear that Capacity Providers with multiyear contracts, unproven Capacity Providers and existing Capacity Providers with less than 50 MW of registered capacity face the same incentives and therefore it's reasonable they should incur termination fees if they do not fulfil their reliability option.

The proposed termination fees seek to find an appropriate balance between simplicity, promoting the right incentives and not prohibitively deterring investment. A progressive termination fee structure is appropriate for this purpose. ESB GWM does not think the proposed termination fees achieve this objective for three reasons and this requires re-evaluation.

- The proposed termination fees to apply after the start of the Capacity Year exceeds the indicative Existing Capacity Price Cap, which is clearly unreasonable on existing Capacity Providers. Setting this termination fee equal to the auction clearing price is more appropriate.

- Similarly, the proposed termination fee to apply after the T-1 auction but before the delivery year may similarly disadvantage existing Capacity Providers. Again, a more appropriate fee for existing Capacity Providers is to set the termination fee equal to the auction clearing price.

- If a sharper incentive is warranted for any new build or unproven Capacity Providers who pose a 'higher risk' the applicable termination fees could be set equal to the auction clearing price if the auction clears above the Existing Capacity Price Cap.

There is no reason to require a performance bond from existing Capacity Providers with above 50 MW of registered capacity. In I-SEM all existing Capacity Providers will need to lodge substantial credit and collateral to participate in the various financial and physical markets. Existing Capacity Providers therefore have strong incentives and requirements to be operational in the delivery year.

If the auction purchased 7,500 MW of de-rated capacity the industry had to collectively post 100% of the applicable termination fees equal to €300 million per annum in performance bonds in the Capacity Year. If this requirement was for every delivery year after an auction the total would more than double to €675 million. This is clearly onerous, excessive and unnecessary. ESB GWM strong objects to this potential imposition.

It is less clear that Capacity Providers with multiyear contracts, an unproven ability to deliver or those who are not subject to the Grid Code requirements will have the same incentives as existing Capacity Providers. There is a stronger case to require a performance bond from these participants. The size of that bond must secure the supply of electricity while not discouraging investment.

Other significant parameters

The billing period stop loss limit must find a balance the need for a performance incentive on Capacity Providers to hedge suppliers across the entire Capacity Year without placing excessive risk on Capacity Providers. The proposed stop loss limit equivalent to 50% of their annual stop loss limit fails to strike this balance. A billing period stop loss limit of 25% of the annual stop loss limit corrects this imbalance.

A simple piece-wise linear function is the most appropriate option to price partial ASP for two reasons. First, the lack of sufficient visibility over the level of target operating reserve and the ability of Capacity Providers to respond ahead of the TSOs initiating partial ASP. Second, the potential under option 2 for local security events to trigger a system wide partial ASP would be counter to fact that I-SEM is a single bidding zone for energy and capacity.

ESB GWM responses to the remaining Consultation questions are set out in section 6.

1. INTRODUCTION

ESB Generation and Wholesale Markets (GWM) welcomes the opportunity to submit a response to the Capacity Remuneration Mechanism (CRM) Parameters Consultation (SEM-16-073).

- Section 0 sets out our overarching comments relating to this Consultation
- Section 6 provides our views on the proposed calculation of the auction parameters
- Section 4 explains our position on the proposed substantial investment threshold, termination fees and application of performance bonds
- Section 5 addresses a number of other key parameters
- Section 6 contains our response to the remaining Consultation questions

We would be happy to discuss our views further with the SEM Committee and the Regulatory Authorities.

2. OVERARCHING POINTS

The parameters are critically important to the CRM auction and to ensure the CRM achieves its objectives. ESB GWM has two overarching points relating to this consultation.

2.1 Interdependent markets, market integrity and the potential for unintended consequences

The new wholesale electricity market arrangements are made up of separate but interdependent markets for energy, capacity and ancillary services. The energy market is made up of a financial forward market and three physical markets, covering the day-ahead, intraday and balancing timeframes. In our response to SEM-16-059 we outlined a number of high level interdependencies between these I-SEM markets.

The SEM Committee's proposals in this Consultation add to the concerns expressed in our response to SEM-16-059. The proposed definition of the fixed operating costs makes no provision for the recovery of sunk investment costs, such the return on capital or depreciation, or variable operating costs.[1] Fixed operating costs are part of the proposed formula to determine the net going forward costs, which is used to set the Existing Capacity Price Cap. The formulaic approach to determine the proposed bidding controls also made no provision for the recovery of these costs.

The combination of these proposals in specific circumstances may restrict a generator's cost recovery below long run marginal costs. Generators who are unable to recover these costs in the balancing market or the capacity market would need prices to rise in the energy market to remain financially viable. ESB GWM believes this is a fundamental flaw and effectively amounts to the SEM Committee regulating the power market prices below cost.

ESB GWM appreciates the SEM Committee undertook the recent stock take exercise to assess the design and delivery risks of the I-SEM project. That review concluded that the baseline design of I-SEM is fit for purpose.2 Considering the above, the potential unintended consequences we highlighted in our response to SEM-16-059 and that a number of key decisions are yet to be made we ask the SEM Committee to

[1] SEM-16-073, p. 44.
[2] SEM-16-078, p. 3.

assess the market's integrity and internal consistency as these decisions are made and once the final design is complete.

2.2 The enduring governance framework

In our response to SEM-016-051, we stated the importance of a clear governance framework for the CRM and suggested a number of improvements. The Consultation provides few details of the governance arrangements for the parameters. Undoubtedly this is in part due to the recent stock take exercise. Now that exercise is complete we ask the SEM Committee to produce a comprehensive and complete governance framework for the CRM, ideally this should be part of the upcoming CMC consultation.

- The immediate priority is clarity on the timelines and processes for first auction transitional auction in December 2017.
- The second order priority is process for the subsequent transitional auctions and the enduring framework for the T-1 and T-4 auctions.

This framework should build on the CRM 1 Decision and details in the latest version of the CMC. Content wise, in the same vein as our response to SEM-016-051 we consider it appropriate to include the following processes into the CMC governance framework.

- The recurring procedural timeline to review, consult and approve each parameters ahead of each auction. This should specify the frequency of that review, who the responsible parties are for conducting it and the engagement market participants. This is essentially the step before the procedures in section D.2, D.3 and M.6 of the CMC apply. This is especially important to the auction parameters.
- The information the TSOs and SEM Committee will commit to publish and what information market participants' will need to provide as well as the timelines and format of that information.

3. AUCTION PARAMETERS

The auction parameters are key elements of the CRM and are of high importance to attracting new investment in the all island power sector.

ESB GWM is supportive of the general approach to determine the auction price cap as set out on page 41 of the Consultation. We have a number of observations in specific areas as set out in section 3.1 and 3.2.

Although we are generally supportive of the approach to set the Existing Capacity Price Cap, we have identified a number of issues that materially impact its calculation.

ESB GWM favours option B to set the shape of the demand curve for the first transitional auction.

3.1 The BNE calculation and Net CONE

The Net CONE is typically defined as the estimated fixed costs of the BNE peaking plant, deducting infra-marginal rent earned in the energy and ancillary services markets. The proposed formula is suitable but the input data and assumptions need refinement to be fit for purpose in the new market.

The Consultation proposes three changes to the calculation of Net CONE. We address each proposal below and suggest two further amendments.

Forced outage rate

The Consultation proposes to adjust the FOR assumptions applicable to calculate the infra marginal rent for the BNE. ESB GWM considers it is reasonable to adjust the BNE equation for this purpose.

The Consultation proposes to standardise the applicable FOR to 5%. ESB GWM does not support the use of this value. The TSOs should determine the applicable FOR using the process set out in section 4.4.1 of SEM-016-082a.[3] Using this value would represent the process to determine the applicable de-rating factor if the hypothetical BNE was to enter the CRM auction. On the basis of SEM-16-051a, the BNE's indicative FOR should be 3.6% in line with the gas turbine technology category.[4]

Impact of RO difference payments and ASP

The Consultation proposes to adjust the existing BNE calculation to include the impact of administered scarcity pricing and RO difference payments into the infra marginal rent calculation. ESB GWM supports the inclusion of this adjustment.

Converting name plate to de-rated capacity

The Consultation proposes to adjust the existing BNE calculation to account for de-rated capacity to nameplate capacity. ESB GWM considers this a reasonable adjustment to include. As mentioned above, the de-rating factor should be the output from the process described in SEM-16-082.

Other adjustments to the BNE calculation

ESB GWM questions whether two other aspects of the current BNE approach should also be updated to make sure it is fit for purpose in I-SEM.

- The current BNE calculation assumes a 20 year period to recover sunk investment costs. A higher hurdle rate may be appropriate given the greater levels of risk of operating in the new market and the narrative described in section 2.1 above regarding the recovery of sunk investment costs and the BNE's inability to recover these costs after the expiration of its long-term contract.

- The BNE calculation should reflect the higher credit and working capital requirements of the new market.

Overall, ESB GWM considers the BNE calculation should be adjusted on the basis of the above points. We recognise SEM Committee will set the applicable parameters for the first transitional auction and subsequent transitional, T-1 and T-4 auctions ahead of those auctions.

3.2 Auction price cap

The Consultation favours setting the auction price cap at a multiple of 1.5 times Net CONE for the foreseeable future, since the experience of the SEM is that Capacity Providers have found a capacity payment of less than 1 x Net CONE adequate to cover their "missing money".[5]

This rationale is confusing as it suggests that what was appropriate in SEM is a way to determine what is appropriate in I-SEM. I-SEM is an inherently different market to SEM. A new build Capacity Provider in I-SEM faces a different set of risk and challenges in the form of sharp imbalance prices, scheduling risk and the prospect of having to make difference payments up to the annual stop loss limit of 150% of the annual option fee. Considering the new market's design ESB GWM is of the view that an auction price cap of a higher multiple of Net CONE is more appropriate. This will provide reasonable allowances for variations

[3] SEM-16-082a, p. 11-12.
[4] SEM-16-051a, p. 21.
[5] SEM-16-073, p. 40.

from Net CONE to attract new investment. If the primary concern is mitigating the potential exercise of market power the Existing Capacity Price Cap serves that purpose.

3.3 Existing capacity price cap

The Consultation proposes to use a Net Going Forward Cost calculation as the basis to set the Exist Capacity Price Cap as a multiple of Net CONE. ESB GWM considers this an appropriate approach to employ but we have identified a number of shortcomings in various places. These shortcomings can be grouped into four categories: the Net Going Forward Cost formula, challenges modelling I-SEM, issues with cost data input into the Net Going Forward Cost formula and the use of international benchmarks.

The Consultation states the SEM Committee does not see the need to set the Existing Capacity Price Cap at a level equal to or higher than the Net Going Forward Cost of all Capacity Providers.[6]

The Net Going Forward Cost formula

The Consultation proposes to use the below formula to determine the Net Going Forward Cost.[7]

> Net Going Forward Cost = Max [(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service), 0] + Expected Reliability Option difference payments

The use of gross infra-marginal rent and the inclusion of the expected difference payments makes formula suitable to apply to calculate Net Going Forward Cost in I-SEM.

ESB GWM have a number of concerns about the proposed approach to calculate the different variables that make up the Net Going Forward Cost formula. As mentioned in section 2.1, the SEM Committee's proposed definition of the fixed operating costs makes no provision for the recovery of sunk investment costs, such the return on capital or depreciation, or variable operating costs. This assumes that Capacity Providers either do not have to earn a return on capital or depreciation or that these costs are recovered outside of the CRM. The proposed bidding controls also prevent the recovery of these costs in the balancing market, as we pointed out in our response to SEM-16-059. This Consultation states that the SEM Committee expects Capacity Providers to recover variable operating costs through the energy and ancillary services markets. It remains unclear how or where existing will recover sunk investment costs or whether the SEM Committee believes they have to. This creates a risk for existing generation owners. Newer and potentially more reliable Capacity Providers are especially at risk as they are most likely to have sunk investment costs. It may potentially deter new investors if they perceive they are unable to recover their costs.

ESB GWM considers this is a fundamental flaw and effectively amounts to the SEM Committee fully regulating the energy market price below cost. We fail to see how this is compatible with the SEM Committee's statutory duties.

We also question how the calculation of the gross infra-marginal rent will work in practice with SEM-16-081. The selected auction format option B is an additive approach and will apply for the transitional auctions and potentially other auctions. Buying additional capacity to address locational issues will erode the infra-marginal rent. EirGrid supplementary document published as part of the CRM 1 consultation stated that approximately 220 MW of additional capacity would be sufficient to move from a reliability standard from eight hours LOLE to three hours of LOLE.[8]

[6] SEM-16-073, p. 43-44.
[7] SEM-16-073, p. 44.
[8] SEM-15-044a, p. 10.

Purchasing capacity greater than the capacity requirement will progressively push the effective reliability standard closer to zero and will reduce the likelihood of full or partial ASP at the same time. This will have two potential impacts. First, it will reduce the infra-marginal rent Capacity Providers earn from the energy and ancillary services markets, which potentially increases the amount of 'missing money' Capacity Providers need to earn from the capacity market to justify continued operation. Second, it will reduce the likelihood of Capacity Providers having to make difference payments. However, this is unlikely to be perfectly offsetting for all Capacity Providers.

This introduces a circular problem between SEM-16-081 and the potential to purchase additional capacity and its real potential to impact the infra-marginal rent and therefore the Net Going Forward Cost calculation. ESB GWM remains concerned about potential that both new and existing Capacity Providers may be unable to recover their costs.

Challenges modelling I-SEM

The Consultation acknowledges the necessity to model the gross infra-marginal rent and the expected difference payments will need to be modelled on an I-SEM basis.[9] We believe this is an essential requirement. ESB GWM considers it inappropriate to use SEM based modelling for this purpose. This will be a challenging undertaking. Modelling the frequency of difference payments will be difficult as by their nature these are highly uncertain. Similarly, modelling gross infra-marginal rent on an I-SEM basis will need to factors in scheduling risk and the impact of the proposed bidding controls amongst factors.

Issues with cost data

The Consultation proposes to use SEM Generator Financial Reporting data as the basis for estimating Fixed Operating Costs as part of the Net Going Forward Cost formula. There are a number of reasons why caution should be applied in using this data for this propose. Note, we are only able to comment on our own data submission and as such these comments should not be read as general statements.

First is the suitability of using Non-fuel Operating Costs as a proxy for Fixed Operating and Maintenance Costs. ESB GWM does not consider that Non-fuel Operating Costs are suitable to use in the Net Going Forward Cost formula without making two adjustments. The first is necessary to apportion Non-fuel Operating Costs that are held centrally, which are not allocated to specific stations or units. The remaining Non-fuel Operating Costs are often allocated to one unit for each station, an adjustment is needed to allocate these costs across the units at each station according to their running hours over the year. We would be happy to discuss this in greater detail with RAs.

We recognise and agree with the SEM Committee's position not to publish Non-fuel Operating Costs at a more disaggregated than a technology category level. The Consultation observes that it is not uncommon to see ± €20/kW variations within a particular fuel type and for a particular year. It is difficult to disentangle this reasons for these fluctuations without the disaggregated data so we cannot offer a view in addition to the above paragraph.

Second, ESB GWM agrees that Non-fuel Operating Costs contain a portion of variable operating costs. A station's operating expenditure overhaul costs are included in Non-fuel Operating Costs. Major overhauls are capitalised. Therefore, Non-fuel Operating Costs will include an element of variable operating costs. However, it is unlikely that the vast majority of the Non-fuel Operating Costs are variable as ESB GWM have not undertaken any major overhauls in the 2012-2014 period the RAs have sampled.

The SEM Committee indicates that it may choose to make adjustments to the historical data.[10] ESB GWM would strongly oppose this if it were done without further engagement with the industry. Clearly there is

[9] SEM-16-073, p. 46.
[10] SEM-16-073, para 6.3.23, p. 48.

some uncertainty about the cost data reported by Generators in their Financial Reports and this creates legitimate questions over its appropriateness to use in the Net Going Forward Cost formula. Were the RAs to make adjustments non-transparent manner this would undermine the integrity of the process and its output as well as introducing an unacceptable level of regulatory risk. ESB GWM believes a better solution would be to develop a specific cost reporting template that is fit for its intended purpose. The most appropriate way forward if this is deemed desirable would be through an industry wide forum, similar the rules working group. [DN: do we want to suggest this?]

Selecting the Existing Capacity Price Cap as a percentage of Net CONE

The choice of 50% of the Net CONE as the Existing Capacity Price Cap is somewhat arbitrary. The apparent rationale for it is twofold and the Consultation indicates that a tighter threshold may be appropriate.

1) the SEM Committee estimate that almost all of the plant meeting the capacity requirement could bid Net Going Forward Cost without needing to apply for a unit specific bid limit

2) consistency with relevant international benchmarks

Given the information presented in the Consultation the basis on which the first conclusion is made is unclear. The indicative value of €38.90 kW / year is lower than the average Non Fuel Operating Costs for all but one of the proposed technology categories, which the SEM Committee acknowledge they are using as a proxy for Fixed Operating Costs.

The international benchmarks in table 5 of the Consultation should also be viewed with a degree of caution for the following reasons.

- The Fixed Operating and Maintenance Costs and Variable Operating and Maintenance Costs are displayed in range of currencies and the years in which the costs are reported also vary. Converting for foreign exchange rates and inflation would make these more comparable.

- This analysis ignores other factors affecting costs such as plant age, unit availability and the location of the units. For example, unit availability may be a factor explaining part of this variation. Availability figures are generally much higher in SEM than in the UK. Higher maintenance costs would be a factor in achieving and maintaining higher levels of availability.

- The design of the electricity markets and their associated rules are also different to SEM and I-SEM. This clearly impacts how those participants recover their costs and the various risks associated with operating in those market is a valid consideration that does not form part of the Consultation's analysis.

- This together with the above mentioned cost data issues in the Generator Financial Reports suggests caution should be applied to over relying on these comparisons.

Having considered this, ESB GWM considers the proposal to select 50% of Net CONE as the Existing Capacity Price Cap appears to have very little basis other than being a round portion of Net CONE. Any Capacity Provider who wants to bid above the Existing Capacity Price Cap will have to apply and receive authorisation from the RAs in advance of the auction. As the SEM Committee notes this could impose an unnecessary administrative burden on the industry and the RAs. Further, the SEM Committee has not provided any detail about how this process will work.

In conclusion, ESB GWM considers there a number of material issues to re-examine relating to costs before any decision on the portion of Net CONE to select as the Existing Capacity Price Cap.

3.4 Demand curve

The Consultation proposes three options for the shape of the demand curve for the first transitional auction.

Our response to the CRM 3 consultation stated the demand curve should reflect the shape of changes to the hours of LOLE at different levels of de-rated capacity. In this way the demand curve represents the efficient trade-off between the cost of purchasing extra capacity, beyond the capacity requirement, and the benefit that capacity provides consumers. The TSOs' estimate of the relationship between installed capacity, the number of hours of LOLE, the EEU in MWh, and the cost of EEU to the consumer in €m p.a. when unserved energy is valued at VoLL. This is a useful representation of this trade-off.

The Consultation notes a number of limitation to the TSOs modelling. We agree with these observations and that this creates an element of uncertainty with the results. For that reason ESB GWM considers a shallower demand curve may be more appropriate until the TSOs can satisfactorily resolve those issues. This appears unlikely ahead of the first transitional auction. It is also preferable not to include a second inflexion point on this basis. Therefore ESB GWM favours Option A as the most appropriate the shape of the demand curve for the first transitional auction. This strikes a good balance between a shallow demand curve and outturn capacity price.

Once the TSOs are able to resolve the identified modelling issues ESB GWM believes it would appropriate to move to a steeper demand curve akin to Option B as this would represent the efficient trade-off between the cost of purchasing extra capacity, beyond the capacity requirement, and the benefit that capacity provides consumers. Market participants would also value greater clarity on the approach to set the demand curve for the subsequent T-1 and T-4 auctions.

4. INVESTMENT THRESHOLDS, TERMINATION FEES AND PERFORMANCE BONDS

This section sets out our views on investment thresholds, termination fees and performance bonds.

4.1 Substantial investment threshold

ESB GWM supports the Consultation's proposal to set the significant investment threshold at 50% of the BNE and for this apply to all capacity provides. This view is notwithstanding our above mentioned concerns relating to the calculation of the BNE in section 3.1. We also expect the SEM Committee to update this threshold over time as part of the wider CRM governance process in section 2.2.

This implications of setting a single threshold in this way, effectively rules out any generators planning substantial refurbishments. This is a new build threshold only.

4.2 Application of termination fees

The prospect of a termination fee is a sensible means of making sure all Capacity Providers have an incentive to fulfil their obligation. To determine if this is necessary for all Capacity Providers we must examine the wider set of applicable requirements and incentives.

The Consultation lists five categories of potential Capacity Providers in I-SEM:[11]

- A Capacity Provider that satisfied the substantial investment threshold for a new build or major overhaul and receive a multiyear RO contract;

[11] SEM-016-073, p. 33-34.

- Minor refurbishment or other upgrades to capacity which does not meet the substantial investment threshold;

- New or unproven DSUs;

- Any other Capacity Provider which has not already demonstrated its ability to physically deliver; or

- All existing capacity

These categories can be rationalised into three categories; Capacity Providers with multiyear contracts, existing Capacity Providers and any unproven Capacity Provider. The proposed single substantial investment threshold means there is no distinction between any Capacity Providers who have incurred expenditure below this threshold. Further, any unproven Capacity Providers should be treated equally and in a technology neutral manner.

In I-SEM all existing Capacity Providers will need to lodge substantial credit and collateral to participate in the various financial and physical markets.[12] The forwards and liquidity workstream has identified this as a key issue that potentially acts as a barrier to entry and expansion.[13] Disappointingly, the SEM-16-081 did not propose to amend the Grid Code requirement for existing generators with above 50 MW registered capacity to provide three years notice of their intention to close. Generators with registered capacity below 50 MW, embedded generators or DSUs are not subject to this requirement. This provides strong assurance to the RAs and the TSOs that existing Capacity Providers will be operational in the years lead up to the delivery year and in the delivery year itself. This indicates that it is unnecessary to apply termination fees to Existing Capacity Providers with above 50 MW of registered capacity.

It is less clear that Capacity Providers with multiyear contracts, an unproven ability to deliver or those who are not subject to the Grid Code requirements will be have the same incentives as existing Capacity Providers to participate in the I-SEM financial and physical markets at the time they acquire a reliability option. This indicates a stronger case for applying a termination fees to these Capacity Providers.

4.3 Setting termination fees

The Consultation seeks to find an appropriate balance between simplicity, promoting the right incentives and not prohibitively deterring investment.[14] A progressive termination fee structure is appropriate as there will be fewer and more expensive options to replace any Capacity Provider closer to the delivery year. It is difficult to gauge whether the proposed termination fees achieves this objective. ESB GWM believes three aspects of the proposed termination fees require further evaluation.

- The proposed termination fee to apply after the start of the Capacity Year of €40.00 / kW / year is above the proposed Existing Capacity Price Cap of €38.90 / kW / year. Setting the termination fee above the Existing Capacity Price Cap is unfair to existing Capacity Providers who would have to pay more than they are eligible to receive. A more appropriate termination fee for existing Capacity Providers is the auction clearing price for the delivery year, where the upper limit is the Existing Capacity Price Cap.

- The proposed termination fee to apply after the T-1 auction but before the delivery year of €30.00 / kW / year may similarly disadvantage existing Capacity Providers if the auction clearing price is

[12] The financial forward market for within zone hedging products, financial transmission rights, and the physical day ahead market, intraday market and balancing market.
[13] SEM-016-030, p. 41-45.
[14] SEM-016-073, p. 33.

below this level. Again, a more appropriate termination fee for existing Capacity Providers would be the auction clearing price for the delivery year.

- A sharper incentive may be warranted for any new build or unproven Capacity Providers who pose a 'higher risk' that could be set equal to the auction clearing price if that is above the Existing Capacity Price Cap.

4.4 Performance bonds

Whether Capacity Providers should have to post a performance bond is a similar question to the application of termination fees.

The imposition of a performance bond equal to 100% of the applicable termination fees will impose an excessive burden on all Capacity Providers, as illustrated by a simple example in table 1 of procuring a de-rated capacity requirement of 7,500 MW. From 2022-23 onwards all Capacity Providers would collectively lodge €300 million in performance bonds every year (blue shading).[15] If this requirement applied to every year after an auction the collective performance bond would more than double to €675 million. Setting performance bonds at this level is clearly an onerous and excessive requirement.

Table 1: indicative performance bond requirements

2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
T-4 auction	75,000,000	75,000,000	225,000,000	300,000,000	
	T-4 auction	75,000,000	75,000,000	225,000,000	300,000,000
		T-4 auction	75,000,000	75,000,000	225,000,000
			T-4 auction	75,000,000	75,000,000
				T-4 auction	75,000,000
Total	75,000,000	150,000,000	375,000,000	675,000,000	675,000,000

As mentioned in section 4.2 above, existing Capacity Providers have strong incentives to be operational in the years leading up to the delivery and in the delivery year. A requirement to post 100% of the applicable termination fees as a performance bond in addition to this is an excessive and unnecessary burden. ESB GWM strongly objects to this potential imposition.

We are however supportive of the requirement for Capacity Providers with multiyear contracts, an unproven ability to deliver or those who are not subject to the Grid Code requirements to post performance bonds as they do not have the same incentives as existing Capacity Providers to participate in the I-SEM financial and physical markets at the time they acquire a reliability option. In determining the size of that performance bond a balance needs to be found between securing the supply of electricity and not discouraging new entrants from participating. Such a balance might involve a lower percentage of the termination fees as a performance bond commensurate with the risk of the Capacity Provider.

[15] In this simple example we assume the capacity requirement stays constant at 7,500 MW and the termination fees remain unchanged at the level proposed in the Consultation.

5. OTHER SIGNIFICANT PARAMETERS

In this section we draw attention to two other significant parameters, the billing period stop loss limit and the administered scarcity pricing function. We address the remaining parameters and consultation questions in section 6.

5.1 Administered Scarcity Pricing

The Consultation proposes two options to price partial ASP in the balancing market when the available target operating reserve is depleted below the largest in-feed loss of 504 MW. Importantly, the target operating reserve will be deemed depleted if operating reserve (i.e. POR, SOR, TOR1 and TOR2) cannot be replaced from replacement reserves or ramping within an hour.[16]

1) A simple piece-wise linear function

2) A Loss of Load Probability (LOLP) times VoLL approximation

Option 2 implies partial ASP can rise from the RO strike price, assumed to be €500 MWh, to €2,000 MWh when the target operating reserve level is insufficient to cover the largest in-feed loss. The primary consideration is evaluating these option 2 or variants of option 2 where prices immediately rise to a predetermined level is the visibility Capacity Providers have of the target operating reserve and whether or not Capacity Providers can respond ahead of the TSOs initiating partial ASP. ESB GWM considers option 2 or variants of it are not unreasonable if this criteria is fulfilled. The current warning system set out in section OC9 of the Grid Code appears insufficient for this purpose. This is a major disadvantage of option 2. A warning system similar to the notice of insufficient margin used GB is one option worth consideration.

In our response to CRM 2 ESB GWM expressed concern the SEM Committee had not specified the current governance arrangements for operating reserve. The Balancing Market Principles Statement is one possible way to address this.

ESB GWM is also concerned about the potential for local scarcity events to trigger partial ASP on a system wide basis. This would be counter to fact that I-SEM is a single bidding zone for energy and capacity. The nature of constraints on the all island system will limit the Capacity Providers who could respond to the incident. This is another disadvantage of option 2 relative to option 1.

We also reiterate our support of a static reserve function. This is important this is set in advance of the first transitional auction. Whilst there may be some inaccuracy in this function in outturn, we consider that it is more important to have a clear basis on which Capacity Providers can participate in the RO. Option 1 has a slight advantage over option 2 from this perspective.

Overall, ESB GWM believes option 1 is more appropriate to implement until the above mentioned downside of a sharp pricing signal can be corrected.

5.2 Billing period stop-loss limit

As a general principle, a Capacity Provider that is unable to deliver should face a reasonable risk of losing more than their annual option fee. The CRM 2 consultation discussed a further billing period stop loss limit to profile the potential loss across the Capacity Year, hence spreading the risks for Capacity Providers and providing a year round hedge for suppliers. This requires a balance between placing a performance

[16] Primary, secondary and tertiary operating reserve (POR, SOR, TOR1 and TOR2) and synchronised replacement reserve (RRS), SEM-16-073, p. 10-11.

incentive on Capacity Providers to provide suppliers a hedge across the entire Capacity Year without placing excessive risk on the Capacity Providers.

The Trading and Settlement Code will define the imbalance and difference payment settlement periods as a week. The Consultation proposes to set the billing period stop loss limit as 50% of the annual stop loss limit, equivalent to 75% of their annual option fee. ESB GWM considers this proposal does not achieve the right balance between incentive and risk. This could result in two undesirable outcomes that undermine the overarching aims of the CRM.

- A Capacity Provider that reaches its annual stop loss limit after two periods will have a limited incentive to perform throughout the remainder of the Capacity Year. The CRM Decision 2 selected the Capacity Year will run from 1 October. A single incident lasting two periods (possibly over two days) is more likely to happen over the winter period. The potential requirement to make substantial difference payments early into a Capacity Year. This would appear counter to the objective to provide suppliers a hedge across the entire Capacity Year.

- If Capacity Providers have to make difference payments equal to 150% of their annual option fee they may face significant risk, particularly in the early months of the Capacity Year when they have not received capacity payments from suppliers. Capacity Provider will incur costs if they have to make payments of this order of magnitude at relatively short notice. This could create financial and credit risk for Capacity Providers as well as impacting debt and derivative covenants. The proposal is therefore overly punitive and imposes an unacceptable level of risk on Capacity Providers.

The simplest solution to correct this imbalance is to reduce the billing period stop loss limit to from 50% to 25% of the annual stop loss limit, meaning it would take four rather than two billing periods to hit the annual limit. ESB GWM considers this proposal achieves a better balance between incentives and risk for Capacity Providers.

Another possibility is to reduce the multiple of the annual stop loss limit from 150% in conjunction with the billing period stop loss limit. An annual stop loss limit of 120% of the annual option fee with a billing period stop loss limit of 40% of the annual stop loss limit, which would take three billing periods to hit the annual stop loss limit.

6. RESPONSES TO CONSULTATION QUESTIONS

Question	Answer
2.3.1 The SEM Committee welcomes views on all aspects of this section, including whether you prefer Option 1 (as set out in Section 2.2 above), Option 2 or some intermediate option for the shape and slope of the ASP function, and why?	ESB GWM favours Option 1 as we see two main disadvantages to Option 2. First, Capacity Providers currently have no visibility of the target level of operating reserve or the ability to respond to it. Second, Option 2 creates the potential for local security events to trigger partial ASP on a system wide basis. The nature of the current constraints on the all island system would limit the Capacity Providers who could respond to it. Our reasoning is further explained in section 5.1.
3.4.1 The SEM Committee welcomes views on all aspects of this section, including: A. Which of Options 1 to 3, as set out in Section 3.2, do you think is most appropriate, and why? Alternatively, what other definition of the Supplier Charging Base would you chose and why?	ESB GWM agrees with the SEM Committee's assessment that Option 3 is most appropriate to implement. In addition to the Consultation's analysis, Option 3 shares the costs across the widest customer base, avoids the potential for inequitable cost recovery and is a better fit with the CRM's high level design. The Consultation proposes three options to allocate capacity charges to suppliers where the options vary on the season and or hours across a day. Options 1 and 2 narrow the allocation of capacity charges to the hours in which residential customers consume a higher proportion of their demand. Residential customers could therefore bear a disproportionately high share of these charges under these options and in doing so would cross subsidise industrial and commercial (I&C) customers. Price signals should encourage greater response from the demand side. Only I&C customers are able to respond to the more focused approach envisaged under Option 1 and 2. Until the roll out of smart meters is complete it is unreasonable to impose a price signal on residential customers when they are mostly unable to respond to it. This would potentially result in an inequitable high recovery of capacity charges from residential customers. The CRM is a year round obligation that can be triggered in any settlement period. Focusing the supplier charging base only on the winter period, as proposed in Option 1, is not wholly consistent with the CRM's high level design. Options 2 and 3 are a better fit.
B. Which LIBOR (or other such reference rate) should be used as the BIR, and what the values of the SPR and DPR should be?	ESB GWM considers that LIBOR or the European OverNight Index Average (EONIA) are a suitable reference rate to use as the Base Interest Rate (BIR). LIBOR has two advantages, first the maturity can be set equal to the weekly billing period and the rate is available in Euros and Pound Sterling. The downside of LIBOR is the TSOs may find it difficult to achieve the rate in practice, which the main advantage of EONIA. The applicable surplus premium rate (SPR) and deficit premium rate (DPR) should ideally be rates the TSOs can achieve in practice.

4.6.1 The SEM Committee welcomes views on all aspects of this section, including: A) Do you agree with the SEM Committee's proposed approach to set the DSU floor price at €500/MWh?	ESB GWM supports the SEM Committee's proposal to set the DSU floor price at €500/MWh. The Consultation correctly identifies the need to establish a DSU floor price that is sufficiently high to send a long term signal to encourage investment in DSUs and for them to actively participate in the CRM without any potential distortions to the physical energy markets. The proposed DSU floor price appears to satisfy the SEM Committee's objectives. We would however request the RAs draw on a wider sample period than was undertaken in appendix B of the Consultation to validate the incremental costs and shut down costs before making a final decision.
B) On the assumption that the gas index will be a reference price related to gas obtained from the GB system, do you agree with the carbon intensity factor? Do you have another comments on the approach to setting the gas or oil carbon intensity factors? C) Do you agree with the approach to setting transport adders set out in section 4.4?	The CRM Decision 3 stated the RO strike price formula would include per unit carbon intensity factors (CIG and CIO) and transport adders, and that the CRM delivery body would be responsible for proposing the applicable fuel reference prices (GRP and ORP). The Consultation states it does not make sense to define the carbon intensity factors and transport adders until the reference indices are chosen. As the CRM delivery body has yet to propose the reference prices ESB GWM cannot meaningfully comment on the appropriateness of the indicative parameters. The Consultation indicates the carbon intensity factors and transport adders for the RO strike price will be set by a similar process to the Directed Contracts. We question the appropriateness of this. Given the CRM is to be governed by the CMC not the Directed Contracts regime different carbon intensity factors and transport adders may very well be appropriate. The SEM Committee is yet to decide whether Directed Contracts will feature in the Forward Contracting Obligations (FCO) in I-SEM. We would also caution against any simple rollover of SEM processes and procedures into I-SEM without a comprehensive assessment of its suitability.
D) Do you that the Billing Period Stop-Loss Limit should be set to 0.5 times the Annual Stop-Loss Limit (i.e. 0.75 times the Annual Option fee)?	ESB GWM considers the simplest solution to correct the imbalance between a performance incentive and risk to Capacity Providers is to reduce the billing period stop loss limit to from 50% to 25% of the annual stop loss limit, meaning it would take four rather than two billing periods to hit the annual stop loss limit. Section 5.2 of our response describes our reasoning in greater detail.
5.4.1 The SEM Committee welcomes respondents' views on the issues raised in this section. In particular, the SEM Committee welcomes respondents' views on whether:	As set out in section 4.1 ESB GWM supports the Consultation's proposal to set the significant investment threshold at 50% of the BNE and for this apply uniformly to all capacity provides.

A) You agree with the approach of setting the New Capacity Investment Rate Threshold at around 50% of the gross investment cost of the BNE plant, currently estimated at €310/kW? If not, what is an appropriate maximum size of termination fee for new capacity which achieves an appropriate balance between protecting consumers by the failure of new capacity to deliver, and not providing a barrier to entry for new capacity?	
B) You think that the SEM Committee's indicative schedule of termination fees set out in paragraph 5.3 is appropriate? Please provide evidence for your answer.	Section 4.3 of our response sets out why the proposed termination fees do not find an appropriate balance between simplicity, promoting the right incentives and not prohibitively deterring investment and therefore require re-evaluation.
C) It is appropriate to place termination fees on capacity that does meet the definition of New Build, and if so, at what level, including: a) Minor refurbishment or other upgrades to capacity which does not meet the financial threshold to qualify as New Build; b) Unproven DSUs; c) Any other Capacity Provider which has not already demonstrated its ability to physically deliver; or even d) All existing capacity	ESB GWM believes it is not appropriate to apply termination fees to existing Capacity Providers with above 50 MW of registered capacity as requirements to post credit and collateral and the Grid Code provide strong incentives to be operational in the years leading up to the delivery year and in the delivery year. It is less clear that Capacity Providers with multiyear contracts, unproven Capacity Providers and existing Capacity Providers with less than 50 MW of registered capacity face the same incentives and therefore it's reasonable they should incur termination fees if they do not fulfil their reliability option. This view is further elaborated on in section 4.2
D) Performance Bonds should be required for 100% of termination fees, and should this vary by type of capacity?	ESB GWM strong objects to this potential imposition of performance bond from existing Capacity Providers. To do so would be onerous, excessive and unnecessary. There is a stronger case to require a performance bond from Capacity Providers with multiyear contracts, an unproven ability to deliver or those who are not subject to the Grid Code requirements as these participants may not have the same incentives as existing

	Capacity Providers. The size of that performance bond must secure the supply of electricity while not discouraging investment. Section 4.4 sets out our reasoning in more detail.
6.6.1 Do you agree with the proposed adjustments to the BNE calculation approach set out in section 6.2.8 to 6.2.10 If not, explain why.	ESB GWM has identified a number of issues regarding the BNE calculation. Our detailed response sets these out in section 3.1.
6.6.2 Do you agree with the choice of multiple of 1.5 x Net CONE in setting the Auction Price Cap?	For the reasons set out in section 3.2 ESB GWM believes a higher multiple of Net CONE is more appropriate Auction Price Cap.
6.6.3 Do you agree with the proposed methodology of estimating a generator's Net Going Forward Costs at: Max[(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets),0] + Expected Reliability Option difference payments	ESB GWM has a number of concerns with the proposed methodology to estimate Net Going Forward Costs. These are set out in detail in section 3.3.
6.6.4 Do you agree with the proposed process and data inputs to calculate Net Going Forward Costs as set out in 6.3	ESB has a number of concerns on this issue. These are expressed in section 3.3.
6.6.5 Do you agree with the proposed approach of setting the Existing Capacity Price Cap at 0.5 x Net CONE? If not explain why, your preferred alternative approach and your rationale for the alternative.	The rational for the selection of 0.5 times Net CONE as the Existing Capacity Price Cap is confusing as it bears no resemblance to the SEM data or the international benchmarks presented. This is further explained in section 3.3.
6.6.6 Do you think that the NOFC costs reported by generators to the RAs as part of the SEM Generator Financial Reporting are a good proxy for the Fixed Operating and Maintenance costs that a Capacity Provider may need to recover via the I-SEM CRM, or do you think that the NOFC contain material variable	ESB GWM can only comment on our Generation Financial Reports, but we have a number of concerns about the applicability of the using this data for this purpose. This is discussed further in section 3.3.

cost which can be recovered via the energy / ancillary services market? If the latter, how big an adjustment should the SEM committee make to exclude any variable elements of the NFOC from Net Going Forward Costs included in the Existing Capacity Price Cap?	
6.6.7 Why are reported SEM generator NFOC/FOM costs substantially higher than international benchmarks? Do you think that existing SEM generators have material scope to cut fixed operating and maintenance costs, and if yes, do you think that this should be reflected in the Existing Capacity Price Cap? Explain why.	ESB GWM believes caution should be applied to in overly relying on international benchmarks. We explain our reasons for this in section 3.3.
6.6.8 Which of options A, B or C with respect to the demand curve set out in Section 6.4 do you think is appropriate for the first transitional auction, and why?	ESB GWM support Option A to set the demand curve in the first transitional auction for the reasons set out in section 3.4. Once the identified modelling concerns are satisfactorily addressed it would be appropriate to move to steeper demand curve akin to Option B.
6.6.9 Do you have any other comments on the shape and/or positioning of the demand curve for the first transitional auction?	Please see section 3.4.
6.6.10 If the SEM Committee proceeds to incorporate locational requirements within the I-SEM CRM, do you agree that the costs/risk of implementing local demand curves (as opposed to a minimum requirement) outweighs the benefits?	The SEM Committee's decision on the treatment of locational issues in the CRM (SEM-16-081) will define and represent capacity constraints on a nested basis where the capacity requirement in each area will be specified in MW. The Consultation states that if the SEM Committee does not propose to introduce local demand curves in the first transitional auction. ESB GWM supports this proposal. The inclusion of local demand curves is unnecessary as long as the auction format option B remains in place. This would of course require further evaluation if and when the chosen auction format shifts from option B to option D. ESB GWM reiterates that we are strongly of the view that a single zone for both energy and capacity is in the best interest of Irish and Northern Irish consumers. Any consideration whether I-SEM should move from a single price zone to multiple price zones should be done on a holistic basis following the established procedures in the Capacity Allocation and Congestion Management Guideline. To do

	look at an individual I-SEM markets in isolation could create unintended consequences, such as diminishing levels of competition.
7.2.1 Do you have any comments on the approach to setting the load following parameter set out in the section? Specifically do you agree with the granularity of the parameters, the proposed historically based methodology, and proposed governance approach? If not, why not and what other arrangements would you propose?	The consultation proposes setting the load following forecast parameter to reflect the month on month changes in load as well as the within month products of; peak (17:00 to 21:00), mid-merit excluding non-peak hours (07:00 to 17:00 & 21:000 to 23:00 on business days) and all other hours. ESB GWM view this granularity as a sensible approach to forecasting the load following profile, as it is reflective of the current financial forward products and load profiling and SEM. GWM view the proposed 5 years of historical outturn data from SEM to be used as the best predictor of the forecast load following. This is data should be updated in an annual review to reflect the outturn experienced in the new I-SEM markets.
7.2.2 Do you think that Capacity Providers should be able to trade against load following margin in calendar year +2 and any subsequent years, and should the parameters for subsequent years be scaled to 75% of the calendar year +1 values or some other percentage?	ESB GWM is concerned the Consultation seeks to be overly prescriptive on load following forecast to be used in the secondary traded market. Secondary trading above the load following obligation should not take place further ahead than calendar year +1. Outage data will only be published a year in advance and while no forecast will reflect the outturn values the accuracy of the forecast will diminish the longer the forecast is made. The outage plan is published for a calendar year, while the Capacity Year proposed is October to September. These years should be aligned if possible to increase the accuracy of the forecasts. The existence of basis risk trading the forecast load following may reduce the attractiveness of trading further than the year ahead.