Generation & Wholesale Markets

ESB GWM Response:

Integrated Single Electricity Market

(I-SEM)

Capacity Remuneration Mechanism

Detailed Design

Second Consultation Paper

SEM-15-014

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Contents

1. INTRODUCTION

ESB Generation and Wholesale Markets (GWM) welcomes the opportunity to submit a response to the Capacity Remuneration Mechanism (CRM) Detailed Design Second Consultation. The Consultation covers further key aspects of the CRM including the Interconnector and Cross Border Capacity, Secondary Trading, Detailed Reliability Option Design, Administered Scarcity Pricing, and Transitional Arrangements.

Section 2 below gives a summary of ESB GWM's main comments in relation to this Consultation. Detailed responses are given in Section 3, following the format of the questions set out in the Consultation.

2. MAIN COMMENTS

2.1 Overall comments

CRM Decision 1

Our response to CRM Consultation 2 should be considered in light of our views on CRM Decision 1, which are set out briefly below. Elements of CRM Decision 1 introduce significant complexity to the arrangements and make the detailed design significantly more challenging. In particular, the choice of the Hybrid MRP makes certain options for cross border arrangements and secondary trading potentially unworkable, even though these options may otherwise have been attractive.

In some instances the choice of the Hybrid MRP may penalise reliable capacity which is available, but would not be able to respond in time and is therefore not instructed to start by the SO. Rather than being a capacity product which procures MW for generation adequacy, the RO with a hybrid MRP is actually a combined capacity/flexibility product. This creates overlap with DS3 and energy balancing and therefore there is not a clear distinction between capacity and system services. We are concerned that this will have the unintended consequence of introducing risk for reliable capacity, leading to the need to introduce a risk premium into bids. This issue is particularly acute due to the untested nature of the BM, with no price history to inform judgements of risk premia.

Further clarification is required on how the rules will work for generators subject to TSO actions. In particular, if there is a situation in which the BM price exceeds the strike price, and TSO chooses not to dispatch a plant because it is already position to provide operational reserve, it is not clear how the information flow operates such that the generator is not penalised, or whether in fact the generator would be penalised.

Differences between CRM 2 stakeholder workshop and CRM 2 consultation document

We note that the stakeholder workshop for CRM 2 held in September 2015 set out a Glide Path option for the transition to the enduring CRM. This has been dropped from the Consultation; the reason given at the Stakeholder workshop was that in the SEM-C's view this would be unlikely to achieve State Aid approval. We are of the opinion that stability in the transition is warranted, and we encourage the SEM-C and the Departments to engage with the European Commission on this point. We note that other Capacity Markets (including GB) have had transitional arrangements approved. In other areas where the I-SEM CRM design does not tally with the latest EC working advice, the RAs appear to be progressing these options in any case – for example long term contacts.

2.1.1 Principles

There are a number of principles which we refer to throughout our response regarding complexity, equity and alignment with DS3.

Concern regarding overall complexity

The overall arrangements are increasingly complex and we are concerned about the ability of the RAs to consult widely on the solutions at the required level of detail, and to implement the chosen approaches. The CRM is a new mechanism that has not been trialled anywhere else in the world. Implementation of this mechanism alongside the ETA and untested DS3 arrangements is a risk and we believe that the CRM should allow for gradual introduction of changes. The proposed design has introduced interdependencies, which are arguably unnecessary, making the future evolution of the market design to address the inevitable teething troubles, more difficult and slower. We therefore take the view that complexity should be reduced where possible, at least for a transition period. We make additional proposals for transitional simplification in Section 2.6.2. Whilst it may be possible to run an auction in 2017, we are concerned that it may be challenging to put in place full operational arrangements for the following 2017/18 capacity year. We note that in GB, DECC is still consulting on important areas of operational arrangements such as secondary trading, despite a first Capacity Auction in December 2014.

Equity

It is essential that there is a level playing field with equitable arrangements for all capacity. We note two areas where some proposals would not fit this requirement: cross border arrangements (where some options do not put the same responsibilities on non I-SEM capacity providers), and the potential for long term contracts for new build only.

Alignment with DS3

We are supportive of the efforts of the RAs and TSOs to align elements of CRM and DS3, in particular Pre-Qualification and Implementation Agreements (if the latter are required). However, we challenge the assumption that CRM and DS3 auctions should be aligned in future. We note that providers of capacity are not necessarily the providers of system services, and vice versa.

What is appropriate for DS3 may not be appropriate for CRM, and in particular the treatment of ROs as a "15th product" would severely limit the RAs' options for a CRM auction design. The relative simplicity and price discovery of a descending clock auction, for example, may not be possible for CRM if it were combined with DS3. We do, however, believe that the sequencing of DS3 and CRM auctions should be closely aligned.

2.2 Interconnector and cross-border capacity

Cross border model

In principle a coordinated reciprocal Participant Led cross border model is desired, and this should be a long term goal, coordinated at an EU level. With market coupling, interconnector flows will be directed by the prevailing market prices between I-SEM and GB as determined through the output of EUPHEMIA in the day-ahead market and subsequent trades on the intra-day platform, and ultimately in the balancing markets. Neither the interconnector owner nor non-SEM generators can control the direction of interconnector flows. As the wholesale electricity market transitions to a harmonised European model, interconnector treatment across Europe should be aligned in both the energy markets and capacity markets where possible. Specific interconnector rules for I-SEM capacity that do not apply in a similar way to interconnected markets will be a barrier to competition and harmonisation.

In the absence of properly designed reciprocal arrangements, the options set out in the Consultation all have their drawbacks. In this context, ESB GWM's preferred treatment of cross border capacity is for the Interconnector Led (performance based) model. This will ensure the interconnector treatment in the CRM in I-SEM, while not identical to GB, is reciprocal with GB arrangements. This will also ensure that non-I-SEM capacity providers have similar incentives to deliver as those in I-SEM, rather than being unduly favoured as under the Availability options. However, the Interconnector Led option leaves unanswered questions regarding how the interconnector owner will manage the risk associated with ROs, and the extent to which it is appropriate for the TUoS customer to underwrite these risks.

De-rating factor

We believe the interconnector de-rating factors should be based on forward modelling since historic flows on the ICs under SEM are unlikely to be representative of the flows scheduled by EUPHEMIA once I-SEM is introduced, and the distorting effect of the current SEM CPM design is removed.

ESB GWM advises that a cautious approach should be taken to determine the interconnector de-rating factors. When calculating the de-rating factor the following issues need to be taken into account:

- The interconnector will be scheduled at the day-ahead stage by EUPHEMIA and this position will be refined with intraday trades[1] and ultimately be dispatched by the TSOs (initially through SO-SO trades, and in future via a common European Balancing Merit Order). At this stage in the design, there is a lack of clarity on the I-SEM intraday and balancing markets making it hard to forecast the direction and flows of the Interconnector.

- The security standard of 8 hours LOLE in I-SEM differs from the interconnected GB market security standard of 3 hours LOLE, which might be expected to impact the direction of flows, if the calculations could be shown to be consistent. .

- The possibility of coincidental stress events in I-SEM and GB. This scenario will make it challenging to secure interconnector flows. It is also not clear how administered scarcity pricing and the level of VOLL in GB and I-SEM will directly affect flows in these periods.

- There is limited suitable historical data and the absence of a pan-European stochastic or probabilistic model of LOLE further complicates the task of determining the contribution of cross-border capacity to security of supply.

This means that in all likelihood the chosen de-rating will not be a good representation of the contribution of the interconnector to security of supply. Given there are potentially significantly consequences if that contribution is assumed to be too high, a conservative de-rating appears sensible, at least until there is sufficient operational experience under I-SEM, and the wider EU Target Model, to get a better understanding of how interconnectors behave under stress conditions.

2.3 Secondary trading

ESB GWM agrees that direct secondary trading is required to allow Capacity Providers to cover Reliability Option exposure when a unit is unavailable. The choice of the Hybrid MRP is the main barrier to financial back-to-back trading (and an example where complexity in one area creates difficulties in another area). However there are some circumstances where a financial arrangement between participants may be attractive and workable, and therefore financial back-to-back trades between participants should be allowed and even encouraged to develop. This would provide an alternative risk management tool relative to having to 'piece together' multiple back-to-back trades with small portions of non-de-rated capacity with multiple counterparties which may incur significant transaction overheads and costs.

Our view is that direct secondary trades should be custom products, with key parameters such as the duration (in days) and MW value agreed between buyers and sellers. As each unit's outage will create a bespoke Reliability Option exposure in a self-determined time frame, participants should be free to construct their own deals and report re-allocation to the settlement body. We encourage the RAs to

[1] The exact mechanism for this will become clearer as the X-BID intraday solution is developed.

consider streamlined arrangements for secondary trades that allow short term transfers of the obligations and rights of the RO to be conducted with low overheads. This should include arrangements for re-nomination with the settlement body that are not onerous (assuming both parties are already pre-qualified).

A centralised secondary trading platform for go-live is not required to enable direct secondary trades, and the investment cannot be justified until it is clearer what the requirements from the market are. Should a central market be developed, it should be optional and not mandatory.

Interaction with load following obligation

In low demand periods, a Capacity Provider's RO will be reduced in outturn by the load following obligation. We assumed that load following works in the following manner: the Capacity Provider is assumed to hold the full de-rated RO at all times, and the load following is applied only to difference payment calculation[2]. Therefore additional secondary purchases are not possible (until the window in which trades above de-rated capacity can occur).

If this is correct applies, then secondary purchasing of ROs above load adjusted de-rated capacity should be allowed to take place one year ahead of delivery in order to allow cover for maintenance outages. The one year ahead time frame has been chosen to line up with the fact that outage schedule will be known one year in advance and to match the contracts that generators will have in place with OEMs and other contractors. The duration purchases above de-rated capacity should be sufficient to cover typical major maintenance outages[3].

Secondary trading timeframes

Secondary trading should in principle be allowed ahead of commissioning to allow new Capacity Providers to manage any delays to commissioning, although this situation may already be explicitly handled under the Implementation Agreement.

In theory a Capacity Provider could completely trade out of its RO, to an alternative new provider that did not win in the auction. This would be as an alternative to centrally surrendering their RO and facing Termination fees. We would be concerned if secondary trading weakened incentives on new Capacity Providers to deliver, and therefore suggest that new Providers should not be able to bilaterally trade out of their Obligation entirely.

As set out above, secondary trading above de-rated capacity should be allowed 1 year ahead of delivery. In order to provide cover for unforeseen events, secondary trading should be allowed close to delivery, at least until shortly before the DAM closes. In the period between the DAM closing and real time, secondary trading may need to be disallowed since participants may be able to trade out of a developing market exposure. We have no objection to secondary trading being allowed after delivery but fail to see the merit in or requirement for this arrangement.

Stop loss transfer

In the case that a Capacity Provider A wishes to secondary trade their Reliability Option for a closed and temporary period such as an outage then in this case, freezing the stop loss limit for Capacity Provider A

[2] This appears to be the approach set out in Appendix B of CRM Decision 1

[3] A related question is whether the RO should dis-apply during outages outside of the Capacity Provider's control – e.g. maintenance on the transmission connection assets. We note the proposal that delays in connections for new capacity would not lead to Capacity Providers incurring penalties.

and setting the stop loss to zero for the new Capacity Provider B would be more appropriate as this fully incentivises Capacity Provider B during the period of the transfer.

If a Capacity Provider A seeks to completely exit the market then secondary trading the RO to new Capacity Provider B should be an option. In this case, the Capacity Provider B should take on an RO with the stop loss reset to zero. Otherwise there is a risk that Provider B will not face as strong incentives to deliver as other Capacity Providers. We note that consideration has not yet been given to Termination clauses in capacity agreements themselves (i.e. not the Implementation agreements), specifically the terms under which Capacity Providers will be able to exit the market, without secondary trading.

2.4 Detailed Reliability Option design

2.4.1 Reliability Option length

ESB GWM favours sequential annual RO contracts for all capacity, and certainly until the market has become established and reliable prices are established. The existing SEM CPM has not provided multiple year certainty on capacity revenues and yet has attracted significant new entrant generation. Capacity investments in a competitive market are made with a significant element of commercial risk, and it is not the job of a CRM to remove all commercial risk for Providers.

Furthermore, long term contracts entail a regulated transfer of significant risk to consumers, well beyond what a commercial entity would likely take on in a similar situation, e.g. suppliers will typically hedge not more than 3 years in advance. Fixed price contracts for greater than 3 years are not a common feature of energy market (Power Purchase Agreements for renewables may have a tenor of up to 15 years but these are index deals rather than fixed price).

International best practice does not indicate that long term contracts are required, and indeed there are multiple examples of unintended consequences. The RAs have highlighted three markets in which longer term contracts are let, but not the multitude of markets in which they are not. We note that in GB, the CM has had mixed results in bringing new capacity forward under long term contracts noting that the single CCGT which achieved a long term contract, Trafford Power, is not expected to deliver on time. The GB CM has awarded contracts to a volume of small scale diesel and gas engines, and questions have been raised as to whether this is a truly economically efficient and desirable outcome.

Currently, I-SEM is considered to be oversupplied with capacity relative to an 8 hours LOLE security standard (unlike GB for example, where the CM was introduced in response to a perceived need to attract new entry). Even if long term contracts are considered to be a requirement for new entry, we do not see the immediate requirement to introduce these contracts, and there are significant risks in issuing long term contracts at prices established in an auction which is untested. Experience of capacity markets in the US suggest that a number of changes are required to nascent capacity markets before the prices become reliable, and longer term contracts in these markets were introduced at a later date.

We note that if multi-year contracts are issued, this creates challenges for the auction design. It is important to consider how the additional value to a capacity provider of a long term agreement (and additional cost to consumers) is taken into account in the auction. If contracts of widely differing lengths are to be offered, a mechanism is required for fairly reflecting the additional risk on consumers for taking on long term contracts. We note that DECC's recent consultation on reforms to the GB Capacity Mechanism has ruled out a Price Duration Equivalence methodology as being unworkable. The Dot.Econ report on DS3 auction design also notes the issues with auctioning different products in the same auction.

Long term agreements also lock out the potential for innovation, e.g. from the demand side. It is a commonly held view that DSUs are unlikely to be able to commit for multiple years.

We are therefore of the view that contract length should be limited to one year. Given annual contracts, it would be appropriate to offer these with a short lead time of one to two years.

Impact of offering multi-year contracts

If the RAs are able to present convincing evidence that multi-year contracts lead to increased efficiency and therefore choose to offer these contracts, then these contracts should be short term (e.g. up to three years). Furthermore, if contracts of greater than one year are available, all potential Capacity Providers should have a choice of contract length, to avoid any distortions in the market. We note that if three year contracts are available to all Capacity Providers, there may be a concern that the first auction would lock in all or most of the capacity requirement for the entire 3 year period, leaving nothing to be allocated for year 2 or year 3. A possible solution to this issue is to auction a 'ladder' of capacity requirements, with auctions for equal volumes over e.g. a 3 year period. We recognise that there may be concerns about splitting procurement over multiple auctions, although this is no different in principle to holding T-4 and T-1 auctions for delivery in the same year – there is a split in volume, and a difference in prices achieved for the same delivery year.

Either approach would require a combinatorial auction to allocate different length contracts at lowest cost (similar to that set out in Section 6 of the CRM 2 Consultation).

Classification of Capacity Providers

As set out above, ESB GWM's view is that all Capacity Providers should be treated equally: new and existing plant should have access to any longer term contracts. If the RAs do chose to treat new and existing plant on an unequal basis, we would prefer Option 2, with a strict definition of tangible facts. We recognise that there may also be a role for a cost threshold (Option 1) as an additional tangible fact.

Maximum available reliability option lengths

As set out above, ESB GWM's view is that contracts should be ideally be limited to one year at least initially, and no more than 3 years. If the RAs do chose to treat new and existing plant on an unequal basis by offering longer contracts to new Capacity Providers, we are of the view that maximum contract lengths should not discriminate by technology.

Alignment with DS3

We are supportive of the efforts of the RAs and TSOs to align elements of CRM and DS3, in particular Pre-Qualification and Implementation Agreements. However, we challenge the assumption that CRM and DS3 auctions should be combined in future. We note that providers of capacity are not necessarily the providers of system services, and vice versa.

What is appropriate for DS3 may not be appropriate for CRM, and in particular the treatment of ROs as a "15^{th} product" would severely limit the RAs' options for a CRM auction design. The relative simplicity and price discovery of a descending clock auction, for example, may not be possible for CRM if it were combined with DS3.

2.4.2 Option fee indexation

We agree that the option fee should be indexed to a measure of inflation, such as that currently used for the SEM VoLL parameter. Indexation should apply between the auction and the year (or years) of delivery.

2.4.3 Stop loss

We agree that stop loss limits are required. As a principle, a Capacity Provider that is unable to deliver should face the possibility of losing more than the annual option fee. Therefore the annual stop loss limit should be greater than 1x the option fee by a small margin.

Monthly limits are required and should be profiled based on an ex-ante probabilistic view of likely RO difference payments. We recognise that this will be difficult to forecast accurately – but it does not need to be precise and could scale with expected minimum reserve margin in each month, for example. The sum of all monthly stop loss should equal the annual stop loss limit.

2.4.4 Commissioning Window

We do not agree with the RA's proposed period of four years between the Auction Date and the start of the Delivery Year. As set out in Section 2.4.1, we do not agree that long term contracts should be offered to new capacity, and therefore a long lead time between auction and delivery is not appropriate or desired.

However, we provide comments in this section for consideration if the RAs decide to introduce long term contracts for new Capacity Providers.

We do not agree that the commissioning window needs to be standardised between CRM and DS3, since it is also far from apparent that long term contracts are appropriate in DS3 (and run counter to the raft EU Network Code on Electricity Balancing which requires balancing services contracts to be no more than one year in length established no more than a year in advance) and that the auction lead time would be the same for CRM and DS3.

In the context of the proposed 4 year lead time, the Long Stop Date appears appropriate. The penalties for late delivery should be based on the estimated cost to the system of under-achieving the security standard in terms of the increase in LOLE, valued at VOLL. However, in any case a minimum level should be set which is sufficient to incentivise on time delivery. The proposed Delay Liquidated Damages approach may be appropriate for this.

2.4.5 Implementation Agreement

Requirements for implementation agreements are more appropriate to long term contracts for new entry, rather than our preferred approach of annual contracts for all. Our comments in this section are relevant if he RAs decide to introduce long term contracts for new Capacity Providers.

Implementation agreements should be strong enough to prevent new Capacity Providers treating the RO as an option on development rather than a firm commitment.

Milestones

We agree that it is important to set early milestones to track the progress of new capacity. The proposed milestones of Substantial Financial Commitment, Commencement of Construction, Substantial Completion appear appropriate. We do not have specific comments on the proposed additional milestones at this stage.

Progress reporting

We agree that 6 monthly progress reports appear appropriate. Reporting should be coordinated across DS3 and CRM only if appropriate.

Termination conditions

The termination conditions should incentivise early termination where known, to facilitate early re-auctioning of capacity.

Any instance of significant misleading or false information being provided should lead to termination of the capacity agreement. This should apply to implementation agreements, but also to active capacity agreements for existing plant.

Performance bond

Performance bonds should be high enough to prevent new Capacity Providers treating the RO as an option on development rather than a firm commitment. The bond should be based on an estimate of the costs to consumers of under delivery of capacity. We agree that larger projects should potentially incur a relatively larger bond to reflect that the increase in LOLE increases more rapidly as the number of MWs under-procured increases. These values should apply if termination occurs close to delivery, and could be reduced in earlier years to provide an incentive to reveal early failure.

2.5 Level of Administered Scarcity Price

ESB GWM's view is that Administered Scarcity Pricing (ASP) should be as high as possible to incentivise generators to perform at times of system scarcity, and reflect the risk of lost load. Full Administered Scarcity Pricing (FASP) should be based on the value of loss of load (VOLL) as this reflects true scarcity. We are strongly of the view that FASP should not be below the EU Consistent level.

We do not believe that the potential incentive for generators to hold back from the DAM/IDM in expectation of higher prices in the BM should be a significant concern, and we agree that this is mitigated through the RO design. However, the Consultation does not clearly explain the concept of virtual bidding or how it would apply in I-SEM and we request further clarification on this point.

We do not believe that an introductory period is required, since this would not materially decrease the level of market change as a result of the introduction of I-SEM. However, we recommend that the form of ASP is considered in light of the detailed rules for Imbalance pricing, to ensure there are no perverse outcomes in these interactions.

We agree with the proposed definition of load shedding. We encourage the RAs to engage with the TSOs and jointly present a set of limits for consultation. Our comments on the level of deviation are as follows:

- **System frequency:** for a demand control event to be judged to have occurred, our suggestion is that the system frequency should deviate beyond statutory limits and this deviation should persist for longer than the duration of typical reserve services. The duration could for example be between 15 minutes and up to 30 minutes.

- **Voltage:** We request that the TSOs propose limits with relevant justification, for review. Consideration should be given to the fact that voltage varies across the network.

We agree that a static reserve function should be used. For a particular delivery year, this should be set in advance of the first auction for ROs for that year. Whilst we recognise that 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.

The value of X in the function should be set as a result of the TSOs' calculation, but in any case should be significantly higher than any likely level of BM offer. A level of 10% would provide reasonable headroom (assuming FASP is set at VOLL).

ASP should start either when the operating reserve requirement has been reduced at point B, or at the point at which an Amber alert would be called.

With regards to point 5.3.10 that ASP should not apply if operational reserve is reduced but there is plant available to replace this even if it cannot start/ramp up fast enough, we request that the RAs/TSOs provide "Day in the Life" examples of when ASP would and would not apply.

The RAs have not specified the current governance arrangements for operating reserve. In any case, the operating reserve requirement used in ASP should be approved by the RAs before the first auction of ROs for that year, which may require additional governance. We recognise this may differ from outturn operating reserve requirements but with a static function there is already a disconnection between the reality of the system and the shape of the function. Given that VoLL is also an approximation and a highly uncertain value, we are not unduly concerned about trying to specify a highly "accurate" function.

2.6 Transitional issues

ESB GWM is in favour of the glide path option set out in the Stakeholder workshop on 29th September 2015 and we are disappointed that this option has been removed from the published Consultation, initially without explanation although the reason given at the Stakeholder workshop was that in the SEM-C's view this would be unlikely to achieve State Aid approval. There are strong arguments for a managed transition, which include:

- Managing the level of change in the market in Q4 2017.
- Practical implementation issues:
    - The need to deliver an additional auction or set of auctions in summer 2017
    - The requirement to have settlement systems fully operational operating from 1st October 2017, rather than 1st October 2021 (including for example arrangements for secondary trading).

2.6.1 Transition: interaction with lead time and contract length.

The need for a transitional period is a result of the RAs' desire for a 4 year lead time before the first enduring auction. We are not convinced of the case for this particularly when there is unlikely to be much requirement for new generic capacity in I-SEM in the early years (and no evidence for this has been furnished). As set in Section 2.4.1, we prefer single sequential auctions on a year ahead basis, which removes the transition issue.

Moving to the options set out in the Consultation, we are strongly against Option 3. The case for a capacity mechanism, and the decision to include a CRM in the I-SEM design, was made at the High Level Design phase. The arguments for a CRM on an enduring phase should also hold for the transition. The removal of the CRM would imply an entirely different philosophy of energy markets (but only for 3 years). While this option may have the lowest upfront cost, this is a short-sighted option and may lead to inefficient exit of plant from the market and have a lasting detrimental impact. The complete removal of the capacity market for a four year transition period will be detrimental to security of supply, competition and stability.

Option 1 has the advantage of simplicity. We are however concerned with the outcome that Capacity Providers will have a contract for 2017/18 and for 2021/22 but not in between. Capacity Providers may need to include the risk of not receiving an RO in the intervening years into their 2021/22 bid, leading to increased costs for consumers.

Option 2 has some merit in that it avoids the problem of Option 1, however it would lock in the bulk of capacity costs in a single auction. International experience of capacity mechanisms suggests that there are often refinements and rule changes after the first capacity auction. Option 2 would not allow for this learning to take place. We also note that neither the Consultation nor the example presented at the stakeholder workshop comments on clearing price determination in a block auction. As the Dot.Econ paper supporting the DS3 auction consultation shows, clearing price determination in combinatorial blocks is not necessarily trivial.

We therefore propose a variant of Option 1, which is that a series of auctions for single years be held in sequence (spaced apart by e.g. one month), in advance of the first enduring auction. This would allow participants to have a known 2019/20 position before entering the enduring auction. It also allows for learning for participants from auction to auction (unlike Option 2). However, like Option 2 it would probably not allow for rule changes between auctions.

2.6.2 Additional transitional measures

The Consultation requests comments on additional transitional measures that may be required. We believe there is a case for the design parameters for the interim ROs to differ from the enduring ROs. We discuss each of these design considerations below.

Security standard

To avoid a cliff edge in I-SEM capacity in 2017/18, there should be a managed transition of auction volume, from the current volume of de-rated capacity to the volume required based on the new approach (as set out in CRM Decision 1) for 2020/21. We recommend a simple straight line approach between now 2017/18 and 2020/21. This will allow the TSOs to develop experience of managing the system with a lower capacity margin.

Auction parameters: Price floor and demand curve

The RAs have previously indicated the possible need for a price floor in the auctions during the transitional period. The RAs have expressed an opinion that this would be unlikely to get State Aid approval, however we note the precedent from the GB CM of having interim measures for a transitional period (in the GB case, in the form of simplified cross border treatment).

A shallow demand curve in the auction would mitigate the risk of very low or very high prices in the transitional auctions, whilst also providing mitigation against any potential concerns about market power in the auction. The demand curve could be constructed with the security standard as a centre point on the curve, with a range that allows for significantly more capacity to remain on the system if prices are low enough, and conversely ensures that volume reduces if prices are above this point (whilst respecting a minimum required volume).

Market Reference Price

The RAs have indicated that the Market Reference Price (MRP) for enduring ROs will be based on “Option 4b”, the hybrid of the Day-ahead Market, the Intra-day Market and the Balancing Market. As well as being overly complex, this introduces Balancing Market price risk to holders of ROs. In order to mitigate participant risk in the transitional period an option could be to use the Day-ahead Market price as the MRP for the interim ROs. The advantage of this approach is that it would remove an interdependency between the BM design and CRM, when it is very likely that adjustments will be required to the calculation of imbalance prices after go-live. Any material change could, in extremis, invalidate the basis on which interim ROs had been auctioned.

3. RESPONSES TO CONSULTATION QUESTIONS

Question	Answer
2.6.1 Interconnector and cross border capacity	
A. Which of the approaches to cross border capacity do you prefer and why? (For the Provider Led and Interconnector Led approach, please specify whether you prefer the "Performance based or "Availability based" variant)	In the absence of properly designed reciprocal arrangements, ESB GWM's preferred treatment of cross border capacity is for the Interconnector Led (performance based) model. This will ensure the interconnector treatment in the CRM in I-SEM while not identical to GB, is reciprocal with GB arrangements. This will also ensure that non-I-SEM capacity providers have similar incentives to deliver as those in I-SEM, rather than being unduly favoured as under the Availability option. We set out brief comments on the other options below. **Net Demand model:** We see a potential role for this approach as a simple transitional model. Arguably, under this model the de-rating factor for interconnectors could be lower since there is no additional incentive on any capacity to deliver (although all such incentives are extremely indirect in any case). **Interconnector led (availability):** This option fails on grounds of equity, as it provides an advantage to non-I-SEM capacity (ICs in this case) and does not hold non-I-SEM capacity to the same standards as I-SEM capacity. **FTR Led:** We understand the attraction of this model as it leads to a more economically rationale alignment of the incentives and risks to the interconnectors and non-I-SEM capacity. However, the timing of the FTR auctions and the capacity auctions do not align, as stated in the consultation. GWM understands the timing issues with FTR Led option but believes that the issue on timing of FTR auctions could be solved by interconnectors holding ROs until FTR auctions and then bundling the RO with the FTR (which effectively creates a variant of the Hybrid option) We note the issue with expiration at Day Ahead (an issue which is created by the choice of a Hybrid MRP). In theory the settlement proposed for IDM and BM under the Participant Led (performance) option could be introduced at this stage. A concern with this approach is that it may limit the development of financial trading and liquidity in FTRs, since FTRs will closely linked to ROs. We do not agree that an FTR Led approach reduces signals for upstream investment. **Provider Led (performance):** This option does not recognise the role of the ICs at all, and is therefore not ideal. It is important that

	under this model, eligibility should not extent beyond directly interconnected markets. We consider that the proposed ability to hold capacity agreements in GB CM and I-SEM CRM could lead to ‘double dipping’ unless it can be demonstrated that stress events are unlikely to be coincident and hence a provider can make a positive contribution to capacity adequacy across both markets. It will be relatively easy to run the auction, but hard to settle without imposing potential losses on non-I-SEM participants which cannot be hedged/managed. As for the FTR Led approach, this approach appears to require participants to hold FTRs for their RO volume. With either Provider Led approach, the need to qualify and monitor generators in a non-I-SEM market is likely to present significant practical barriers. We wish to clarify that under a Provider Led model, we assume that the non-I-SEM participant would need to be in a directly connected market (i.e. currently only GB). Otherwise, multiple de-rating factors would need to be derived and then aggregated in some form to derive e.g. de-raring factors for capacity in France. This would be an unnecessary addition of complexity. **Provider Led (availability):** This option fails on grounds of equity, as it provides an advantage to non-I-SEM capacity and does not hold non-I-SEM capacity to the same standards as I-SEM capacity. **Hybrid:** We understand the attraction of this model as it leads to a more economically rationale alignment of the incentives and risks to the interconnectors and non-I-SEM capacity (as for the FTR Led model). However, in combining the requirement to potentially settle both the interconnectors and the non-I-SEM Capacity Providers, it introduces all the settlement and monitoring issues set out for the Provider Led (performance) option.
B. Should the de-rating of interconnectors be based on historic performance, or include forward modelling to project how its performance could change in the future.	We believe the interconnector de-rating factors should be based on forward modelling since historic flows on the ICs under SEM are unlikely to be representative of the flows scheduled by EUPHEMIA once I-SEM is introduced. ESB GWM advises that a cautious approach should be taken to determine the interconnector de-rating factors. The chosen de-rating is unlikely to be a good representation of the contribution of the interconnector to security of supply. Given there are potentially significantly consequences if that contribution is assumed to be too high, a conservative de-rating appears sensible, at least until there is sufficient operational experience under I-SEM, and the wider EU Target Model, to get a better understanding of how interconnectors behave under stress conditions.
C. If there is a preference for the “Interconnector led performance based” approach there will be a	There is an established method under CACM Article 43 ***Methodology for calculating scheduled exchanges resulting from single day-***

need to allocate total interconnector flows between specific interconnectors. Which of the specific approaches set out in 2.4.6 do you prefer? These approaches were: • Balance interconnector utilisation; • Pro-rata to interconnector metered flow; and • Complex power flow modelling	***ahead coupling*** to allocate total flow between specific interconnectors. In the ETA building blocks decision (SEM-15-064), the RAs have already decided that the interconnectors should be modelled separately in Euphemia to account for their different loss factors" "Losses will be modelled separately on the Moyle and East-West Interconnectors subject to this being confirmed as possible by the EUPHEMIA developers." Therefore it appears that DAM flows on Moyle and East-West will be an output of EUPHEMIA and a separate approach for the CRM is not required (at least for the DAM component).
D. If there is a preference for the "FTR Led" approach, which of the specific approaches set out in 2.4.15 (net or gross) do you prefer for the allocation of non-day-ahead flows?	We do not have a preference for the FTR Led approach. However, if this approach was adopted we would recommend that FTR holders are able to bid for a specific ratio of RO per MW of FTR. This ratio would be closely related to, if not identical to, the interconnector de-rating factor. (Participants could separately hold FTRs but this would be outside of the scope of RO settlement calculations). 2.4.19 suggests that DAM flows would be allocated to FTR holders in proportion to their FTR. Therefore, it appears that all FTR holder would be in the same position, and the net/gross question becomes irrelevant since the allocation of flows would be the same. If the DAM allocation exceeds the RO volume, then the IDM and BM flows are irrelevant, as is the case for I-SEM capacity.
E. If there is a preference for the "Performance based Provider Led" approach, which of the specific approaches set out in 2.4.25 do you prefer for the allocation of intra-day and balancing market trades? • As traded • Pro rata to Reliability Option (in which case- do you prefer "gross" or "net") • Ignore – all in Balancing Market	We do not have a preference for the Provider Led (Performance) approach. A major reason for this is the complexity of settlement under this option. It would be feasible to settle all remaining RO volume (that is not allocated Day Ahead) in the BM.

F. If there is a preference for the "Hybrid " approach: • Should this be paired with the "Delivery Based" or "Availability Based" provider led approach? • Should interconnector participation be mandated or voluntary? Please provide a rationale for all of your responses.	We do not have a preference for the Hybrid approach. However, if this option is chosen it should be implemented with the Performance based model since Availability based models fail on the criteria of equity of treatment of I-SEM and non-I-SEM capacity. Interconnector participation in this model should not be mandatory. However if the interconnector chooses not to participate, then the interconnector capacity should not be included in the auction, since this is a signal that that Interconnector owner is not prepared to financially back the ability of the interconnector to deliver. Therefore the capacity of the interconnector that does not participate would not be included in the implicit or explicit auction for non-I-SEM capacity.
3.7.1 Secondary trading	
A. Do respondents agree that direct secondary trading of Reliability Options should be permitted?	Direct secondary trading of Reliability options should be permitted.
B. Should secondary trading of Reliability Options be via an organised secondary platform? If so, which one of the options is preferred?	A centralised secondary trading platform for go-live is not required to enable direct secondary trades, and the investment cannot be justified until it is clearer what the requirements from the market are. Should a central market be developed, it should be optional and not mandatory.
C. Do respondents believe that "back to back" trading to lay-off exposure to difference payments should be permitted?	The choice of the Hybrid MRP is the main barrier to financial back-to-back trading (and an example where complexity in one area creates difficulties in another area). However there are some circumstances where a financial arrangement between participants may be attractive and workable, and therefore financial back-to-back trades between participants should be allowed and even encouraged to develop. This would provide an alternative risk management tool relative to having to 'piece together' multiple back-to-back trades with small portions of non-de-rated capacity with multiple counterparties which may incur significant transaction overheads and costs.
D. With respect to the creation of a centralised Reliability Option secondary market platform: i. Is there likely to be sufficient demand for secondary trading to justify the cost of the development of a	**All questions in this section are independent of whether or not a centralised market is developed** i. ESB GWM does not see the requirement to have a centralised platform for secondary trading at go live. A secondary trading platform should organically grow from a requirement to trade. A bilateral market place will have the lowest cost to the consumer. ii. Capacity providers should be allowed to trade above their de-rated capacity up to their name plate capacity,

centrally organised platform; ii. Do respondents think that capacity providers should be allowed to acquire Reliability Option volume in excess of their de-rated capacity (plus the tolerance margin), and if yes, how the limit on Reliability Option volume for the net primary and secondary volume should be structured? iii. What limits should be placed on secondary trading timeframes, including: the timing of secondary trade execution – how soon after the auction should they be allowed, and how late in relation to real item delivery should they be allowed; and the length of the Reliability Option contract that can be traded? iv. Should the capacity market delivery body maintain the processes and capability to undertake pre-qualification throughout the year, and what service standards are required for processing new applications?	up to a year ahead of delivery in order to cover scheduled maintenance outages. iii. Capacity providers should be allowed to purchase above their de-rated capacity up to a year ahead of delivery in order to cover scheduled maintenance outages. This should be allowed unit closure of the DAM. Trades above de-rated capacity should be limited to the duration of a typical major maintenance outage. iv. Capacity providers qualifying for the primary RO auction should be pre-qualified for secondary trading. The additional Pre-Qualification of capacity on a year round basis for secondary trading is likely to be infrequently used, but should be available. The capacity market delivery body should maintain processes and capability to undertake pre-qualification throughout the year. v. There is a need to distinguish between a full, long term transfer, and a more lightweight temporary transfer for outage cover. GWM envisage two styles of secondary trading: - A limited reassignment of the rights and obligations under the RO for a closed and temporary period. The stop loss limited should be "frozen" for Capacity Provider A (the original owner) and reset to zero for Capacity Provider B. Therefore Capacity Provider B is fully incentivised during the outage period. - A full transfer of the RO permanently. A Capacity Provider looking to trade out completely may well have suffered significant losses, so it is reasonable to argue that stop losses should not transfer along with all Obligations under the contract. In all cases, if a provider reaches a stop loss they have no incentive to delivery (other than energy revenues of course). This is an issue with having stop loss arrangements, rather than a specific secondary trading issue.

v. Should a secondary acquirer of a Reliability Option start from a zero position against each "stop-loss" limit, or should the loss transfer?	
4.7.1 Detailed Reliability Option Design	
Reliability option contract length questions	
A. Principle of Longer Term Reliability Options: i. Do respondents agree that plant requiring significant investment should be able to avail of longer term Reliability Options? ii. Do respondents agree that existing plant should be restricted to reliability options with a term of 1 year? iii. Do respondents believe that longer term Reliability Options should only be available to new-build plant, or should also be available to existing plant where significant investment is being made to enhance or maintain its capability to provide capacity?	i. We do not agree that plant requiring significant investment should be able to avail of longer term ROs. Contract length should be limited to 1 year. Given annual contracts, it would be appropriate to offer these with a short lead time of 1-2 years. If multi-annual contracts are offered, these should be available to all Capacity Providers ii. If multi-annual contracts are offered, these should be available to all Capacity Providers, and limited to a maximum of three years. iii. If the RAs do chose to discriminate between new and existing plant, then it is logical to extend to longer term contracts to existing plant making investment.

A. Classification of plant as new, upgrade or existing i. Do respondents have a view on which approach should be used to classify capacity providers as “new”, “upgrade” or “existing”? ii. Do respondents prefer the approach of classifying providers as “new”, “upgrade” or “existing”, please indicate your view of the criteria, evidence and thresholds that should be used to inform this classification.	i. If multi-annual contracts are offered, these should be available to all Capacity Providers. If the RAs do chose to treat new and existing plant on an unequal basis by offering longer contracts to new Capacity Providers, the determination should be made on Option 2: tangible facts, perhaps with a cost threshold in addition (Option 1) which is another form of tangible fact. ii. We have no specific comments to make on definitions of thresholds or tangible facts at this stage.
B. Maximum available Reliability Option lengths i. Do respondents have a view on the appropriate maximum Reliability Option lengths that should be available to new-build and upgraded plant? ii. How do respondents view the Reliability Option lengths in relation to the five generic frameworks set out in this section?	i. Contract length should be limited to 1 year. If longer term contracts are offered to new capacity only, these should be short in duration (a maximum of three years), therefore of the options proposed we would favour Shortest Economic Life. ii. If longer term contracts are offered to new capacity only, these should not discriminate by technology, since all Capacity Providers are providing an equivalent service (if de-rating factor are accurate)
Stop-loss limit questions	
C. Do respondents favour the I-SEM Capacity Year running from October to September, with annual stop loss limits	Yes, this appears to be appropriate.

applying over that I-SEM Capacity Year?	
D. Do respondents believe that "per event/day" and "per month" limits are required in addition to the annual stop loss limit?	We believe that per month limits are necessary. Per event limits may be overly complex so a daily limit (or rolling 24 hour limit) may be appropriate.
E. Which approach do respondents favour for the definition of the Per Day/event limit?	A simple daily or rolling 24 hour limit
F. Please provide views on the appropriate levels for the each of proposed stop loss limits.	As a principle, a Capacity Provider that is unable to deliver should a reasonable risk of losing more than the annual option fee. Therefore the annual stop loss limit should be greater than 1x the option fee by a small margin. The extent to which it needs to be higher depends on the likelihood of monthly or per event limits binding. Monthly limits should be profiled based on an ex-ante probabilistic view of likely RO difference payments. We recognise that this will be difficult to forecast accurately – but it does not need to be precise and could scale with expected minimum reserve margin in each month, for example. The sum of all monthly stop loss should equal the annual stop loss limit.
<u>Commissioning Window and Implementation Agreement</u>	
G. Is a period of four years from the Auction Date to the start of the first Delivery Year appropriate?	We do not agree with the RA's proposed period of four years between the Auction Date and the start of the Delivery Year. As set out in Section 2.4.1, we do not agree that long term contracts should be offered to new capacity, and therefore a long lead time between auction and delivery is not appropriate or desired. .
H. Does setting the Long Stop Date at 18 months after the start of the first Delivery Year strike the correct balance between the costs incurred by the market and the ability for delayed or longer running capacity projects to be completed?	Yes
I. Are the proposed milestones reasonable?	Yes
J. Are there any other milestones, especially prior to Substantial Financial Commitment, which could	No comment

be used to add security to the delivery of new capacity?	
K. What proportion of the contracted capacity is appropriate to use to identify Substantial Completion?	No comment
L. Is six-monthly reporting appropriate?	Yes. We agree that 6 monthly progress reports appear appropriate. Reporting should be coordinated across DS3 and CRM only if appropriate
M. Do any (or all) of the reports need to be independently verified?	Yes, on six monthly basis
N. Does 18 months provide sufficient time after the Auction Date to achieve Substantial Financial Commitment?	No comment
O. Is it appropriate to terminate a Reliability Option for failure to achieve Substantial Financial Commitment?	Yes. The termination conditions should incentivise early termination where known, to facilitate early re-auctioning of capacity.
P. Should failure to achieve any other milestones (within a suitable window) trigger termination of the Reliability Option?	No comment
Q. Is it appropriate to partially terminate a Reliability Option if it can achieve "Minimum Completion? What level should be set for Minimum Completion?	No comment
R. If a Reliability Option is terminated under the terms of the implementation Agreement, should this project be "sterilised" for a period of time following the termination and be unable to participate in capacity auctions?	No comment

S. Should the I-SEM consider terminating Reliability Options if the information submitted as part of the qualification process is discovered to be false or mis-leading?	Yes. Any instance of significant misleading or false information being provided should lead to termination of the capacity agreement. This should apply to implementation agreements, but also to active capacity agreements for existing plant.
T. Do respondents agree that the level of the performance bond should be based on a pre-estimate of the cost to the market of non-delivery of contracted capacity?	Yes. Performance bonds should be high enough to prevent new Capacity Providers treating the RO as an option on development rather than a firm commitment. The bond should be based on an estimate of the costs to consumers of under delivery of capacity.
U. Do respondents agree with the principle that the level of performance band should rise over time, reflecting increased costs to the market? If not, what alternative principle should be used and why?	Yes. These values should apply if termination occurs close to delivery, and could be reduced in earlier years to provide an incentive to reveal early failure.
V. At what level in €/MW does the performance bond create a serious barrier to entry? Does this differ for small vs large plant or for different technologies?	No comment
W. Do respondents agree with the principle that use of a fixed €/MW level for all participants, regardless of size, to set the size of the performance bond does not fully capture the costs and risks to the I-SEM and that a more complex approach is needed? Do participants have an alternative preferred method for handling the greater risks to the I-SEM created by larger new capacity projects?	Yes. We agree that larger projects should potentially incur a relatively larger bond to reflect that the increase in LOLE increases more rapidly as the number of MWs under-procured increases.
X. How should the level of the performance bond change over time? Should this have any link to the milestones?	Increase up to cost of non-delivery by year ahead of delivery
Y. Do you consider that the Time To First Delivery	We do not agree that long term contracts are required under either CRM or DS3. However if they are implemented in both it would be

(/Time to LSD) proposed here for the CRM should also apply equally to the delivery of system Services under the DS3 arrangements? If you consider that the time (s) should be different, on what basis/ what rationale should they differ?	appropriate to align timescales, but only if this does not lead to inappropriate measures in the CRM or DS3.
5.5.1 Level of Administered Scarcity Price	
A. Which of the options do respondents prefer (and why) for the enduring level of the Full Administered Scarcity Price (FASP)? I. VoLL; II. EU Consistent (e.g. with GB); III. Euphemia Cap; or IV. Existing SEM PCAP	Administered Scarcity Pricing (ASP) should be as high as possible to incentivise generators to perform at times of system scarcity and reflect the risk of lost load. Full Administered Scarcity Pricing (FASP) should be based on the value of loss of load (VOLL) as this reflects true scarcity.
B. Do respondents agree with the definition of full load shedding (when Full ASP applies) as set out. If not please explain why, and your proposed alternative definition.	We agree with the proposed definition. We encourage the RAs to engage with the TSOs and jointly present a set of limits for consultation. Our comments on the level of deviation are as follows: • **System frequency:** for a demand control event to be adjudged to have occurred, our suggestion is that the system frequency should deviate beyond statutory limits and this deviation should persist for longer than the duration of typical reserve services. The duration could for example be between 15 minutes and 30 minutes. • **Voltage:** We request that the TSOs propose limits with relevant justification, for review. Consideration should be given to the fact that voltage varies across the network.
C. Do respondents agree that virtual bidding removes any incentives on capacity providers to withhold power from the DAM or the IDM to sell in the BM? Do you agree that this applies regardless of what market	We do not believe that the potential incentive for generators to hold back from the DAM/IDM in expectation of higher prices in the BM should be a significant concern, and we agree that this is mitigated through the RO design. However, the Consultation does not clearly explain the concept of virtual bidding or how it would apply in I-SEM and we request further clarification on this point.

power controls are placed on DAM, IDM and BM bids? Do you agree that this applies regardless of the level of the Full ASP? If you do not agree, please explain why.	
D. If stakeholders consider that it is appropriate to set the Full ASP at a lower level for an introductory period they should also set out, how long that introductory period should be and why, or alternatively the principles that the SEM Committee should employ in deciding when to move from the introductory full ASP to the higher rate full ASP.	We do not believe an introductory period is required.
E. If you favour a different level of Full ASP, either for an introductory period, or after any introductory period, please indicate the level and justify your response.	Full Administered Scarcity Pricing (FASP) should be based on the value of loss of load (VOLL) as this reflects true scarcity.
F. Do respondents agree with the proposed approach of using a static approach to setting the piece-wise linear ASP function at the inception of the I-SEM, and if not why not? If yes, do you agree with the proposed approach of setting the piece wise linear equation as a function of the remaining MW of available operating reserve?	We agree that a static reserve function should be used.
G. What should the value of X in Figure 12 be?	The value of X in the function should be set as a result of the TSOs' calculation, but in any case should be significantly higher than any likely level of BM offer. A level of 10% would provide reasonable headroom. ASP should start either when the operating reserve requirement has been reduced at point B, or at the point at which and Amber alert would be called.
H. How far in advance of the start of the Capacity	For a particular delivery year, this should be set in advance of the first auction for ROs for that year. Whilst we recognise that there

Delivery Year should the piece-wise linear function be set. Does this need to be before the T-1 auctions?	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.
I. Do respondents think that any changes need to be made to the governance of the target operating reserve policy. If yes, what are these changes?	The RAs have not specified the current governance arrangements for operating reserve. In any case, the operating reserve requirement used in ASP should be approved by the RAs before the first auction of ROs for that year. We recognise this may differ from outturn operating reserve requirements but with a static function there is already a disconnection between the reality of the system and the shape of the function. Given that VoLL is also an approximation and a highly uncertain value, we are not unduly concerned about try to specify a highly "accurate" function.
6.2.1 Transitional issues	
A. Which of the suggested options (annual auction, block auction, do nothing) do you prefer?	We are favour of year ahead annual auctions for annual contracts, which removes the need for a transition. If the RAs decide on a four year lead time for the enduring auction, We propose that the RAs consider a variant of Option 1, which is that a series of auctions for single years be held in sequence (spaced apart by e.g. one month), in advance of the first enduring auction. This would allow participants to have a known 2019/20 position before entering the enduring auction. It also allows for learning for participants from auction to auction (unlike Option 2). However, like Option 2 it would probably not allow for rule changes between auctions.
B. If you prefer the do-nothing auction, do you believe this should be accompanied by relatively low levels of Administered Scarcity Price?	ESB GWM is strongly against the "do nothing" option. The case for a capacity mechanism, and the decision to include a CRM in the I-SEM design, was made at the High Level Design phase. The arguments for a CRM on an enduring phase should also hold for the transition. The removal of the CRM would imply an entirely different philosophy of energy markets (but only for 3 years). While this option may have the lowest upfront cost, this is a short sighted option and may lead to inefficient exit of plant from the market and have a lasting detrimental impact. The complete removal of the capacity market for a four year transition period will be detrimental to security of supply, competition and stability.
C. Are there any other transitional issues respondents feel that we should take account of when implementing the CRM?	In Section 2.6.2 we propose a set of additional transitional measures for the RAs to consider, including a transitional volume requirement, a shallow demand curve and the use of the DAM as the transitional MRP.