Power NI Energy Limited
Power Procurement Business (PPB)

I-SEM

CRM

Parameters for T-4 2022/23 Capacity Auction

Response by Power NI Energy (PPB)

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Power Procurement Business

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Introduction

PPB welcomes the opportunity to respond to the RAs consultation on the Capacity Remuneration Mechanism (CRM) parameters for the T-4 2022/23 Capacity Auction.

General Comments

The CRM is a critical element of the I-SEM that is essential to ensuring the long term stability and security of supply (SoS) in a small island market. Reliability Options (ROs) are relatively complex instruments that incorporate both a hedge against high spot market prices and scope to recover money that is missing more generally from the energy market. Their operation is further complicated in the context of a small system that is targeting high levels of intermittent generation.

PPB has previously commented on the parameters for the first two T-1 auctions which have or will occur relatively close to the period for which capacity is to be delivered. A key difference for T-4 auctions is the significant increase in uncertainty when forecasting forward by 4-5 years to estimate costs and revenues and hence forecast both “missing money” and payments under the CfD element of the RO. Such uncertainty must be allowed for through higher “uncertainty margins” that should be applied to price caps and where relevant to Unit Specific Costs.

Proposals to allow multi-year contracts to compete with existing capacity without taking account of the impact of the other years in the multi-year term will distort the market and if they were to be compared then a full lifetime analysis should be undertaken (considering all costs – energy, capacity, DS3 etc). However, we do not believe that to be a viable approach as it mirrors the historic “centrally planned” approach that was discredited in favour of the market delivering. The only tenable option is to retain the existing requirement that multi-year contracts are only considered where there is no other single year option available to meet the requirement (market wide or locational).

We welcome proposals to increase the capacity requirement which is a step towards recognising that customers now expect a higher security of supply and the reality that the TSOs will always hold a buffer margin in reserve by disconnecting customers prior to all the reserve being exhausted.

Proposals to withhold capacity from the T-4 auction will result in market distortions through both a lower auction clearing price and the sending of potentially erroneous capacity closure signals. Such price distortion will impair investment decisions and lead to inefficient outcomes for customers. This applies to both the general auction and to the process that seeks to solve for locational constraints.

Our responses to the specific questions posed are set out below.

<u>Responses to the Specific Questions</u>

Chapter 2. ***<u>Treatment of Constraints in T-4 Auction</u>***

Q1: Do you agree with the SEM Committee's proposal to reflect transmission constraints in the T-4 auction?

PPB agrees with the proposal. Reflecting these constraints in the T-4 auction will ensure that where new entry is required then the lead time will facilitate such new entry. If locational constraints were to only be resolved in the T-1 timeframe then it limits the options that could meet such requirements in that timescale and hence may result in inefficient outcomes and costs for customers.

Further, where locational constraints cannot be resolved by securing "additional" capacity for CY2022/23, then waiting until 2021 before seeking to solve the locational constraint would imply that if additional capacity were needed in the T-1 timeframe to solve a locational constraint then that would need to displace contracts awarded in the T-4 auction which would be untenable and provide great uncertainty for anyone who secured a T-4 contract.

Hence the only viable option, unless there is agreement to procure "additional" capacity to solve constraints, is to reflect transmission constraints in the T-4 auctions.

Q2: Do you have any comment on the possible inclusion of multi-year pay-as-bid Reliability Options to meet the minimum Locational Capacity Constraint requirement?

Unless a transparent and robust mechanism can be devised to complete a full lifetime assessment to identify the least cost solution for customers, then multi-year pay as bid TOs should not be permitted.

We disagree with the statement in the CRM locational decision paper (SEM-16-081) that "*the fact that the constraint was incorporated in the T-4 auction would be recognition that the constraint was less transitory*". The constraint may be resolved at any time beyond the capacity year by a range of measures. Therefore any such decision is more aligned with the role of a "Central Planner" but the liberalisation of energy markets has removed such a monopoly role.

As a result we do not believe it is possible to derive a viable means of assessing multi-year contracts against 1 year contracts to reach an efficient conclusion and there is a very substantive risk of generating stranded assets and costs.

The example shown in paragraph 2.2.6 on the basis of a simple comparison of an offer of £91.37/kW/year for 1 year and a 10 year contract at £40/kW/year then makes a sweeping statement that "*Locking-in to a price of £40/kW/year would expect to be a more economical outcome for the consumer*". There is <u>nothing to justify this statement</u> and to do so, as we have highlighted above, would require a lifetime assessment of costs to consumers considering the totality of the components of the final energy price to consumers including Capacity, Energy and DS3 costs etc.

We note the comments in paragraph 2.2.10 that the options of assessing the trade-offs between price and duration remain impractical. However, any simple comparison of multi and single year contracts, as per Options 2 and 3 will be inefficient and produce higher costs for customers. As noted above, we agree that completing a proper economic assessment would be a very difficult challenge but in the absence of that, anything other than Option 1 would be a pure gamble with no justifiable rationale and with the key risk that customers are burdened with a stranded cost.

Q3: Do you have a preference between the options set out above in relation to pay-as-bid offers?

As noted above in our response to Question 2, Options 2 and 3 will result in inefficient outcomes as it is impossible to complete a coherent objective assessment of the options without taking account of the duration and where the objective is least cost for consumers then such an assessment would also need to consider total costs including energy, etc.

The SEMC recognise in paragraph 2.2.10 that such an assessment is difficult and impractical for the first T-4 auction, although we consider that it is unlikely it would ever be possible to complete it objectively and transparently when the decision maker is not exposed to any stranded costs that could arise from the decision.

Option 1 is therefore the only viable option that is economically justifiable.

Chapter 3. <u>Auction Format</u>

Q1: Do you have any comments on the SEM Committee's proposal to move to an auction format based on Auction Format C for the CY2022/23 T-4 auction, following the State aid decision?

We note that the requirement for change is linked to the State Aid decision although given the uncertainty that exists following the first T-1 auction and the generating units that are seeking to close in response to not obtaining contracts, it would be better to have a longer transition period and hence retain the same auction format as used in the T-1 auction for CY2018/19.

There is also nothing to demonstrate the integrity of the Auction Format C process which if it were to be adopted would require very transparent certification. There has also been no proper impact assessment of a change to Format C which is again a concern.

Q2: Do you have any comments on the TSOs proposed AASM for implementing the new auction format, as set out in Appendix A, or the RAs' proposed change to the N parameter?

We note the TSOs' proposal to limit the size of the combinatorial problem to N above and below the marginal offer and the RAs' requested amendment for there to be two separate parameters (N1 and N2) to allow different limits to be applied to offers above and below the marginal offer. There has been nothing published in this consultation paper that provides any impact assessment of this approach when applied to the capacity likely to participate in the auctions. In the absence of such an assessment and also analysis showing the impact on the potential outcomes with different values for "N1" and "N2" would be necessary to enable informed consideration and comment. This analysis must be completed and consulted upon before any final decision is made.

Q3: Do you have any comment on the proposed change to the format to accommodate multi-year pay-as-bid Reliability Options?

In line with our response to the Chapter 2 questions above, we do not consider it viable or warranted to treat one year and multi-year bids simply on the basis of price. They represent two very different commitments and thus cannot simply be treated by ignoring the later years of the multi-year bid since otherwise the outcome will be inefficient and ultimately distort the market

Chapter 4. ***Capacity Requirement***

Q1: What are your views on the potential changes proposed to the CR methodology i.e:

- ***Incorporate some measure of operating reserves in the CR? What MW value?***
- ***Whether the 8-hours LOLE standard should be tightened (reducing the LOLE target). What level do you consider to be appropriate and why ?***

In all PPB's previous comments on the capacity requirement we have highlighted that the capacity requirement determined has been too low and that the actual capacity required by the TSOs has been to a higher standard than 8 hours LOLE. It is also important to note that the actual standard in Northern Ireland is already higher than 8 hours.

Based on actual security of supply over the last number of years and changes in customer expectations, PPB believes that formalisation of a higher standard is appropriate. Alignment of the security standard with our interconnected neighbours would be a sensible approach and hence PPB is supportive of tightening the standard to be 3 hours LOLE.

We also agree that there should also be an uplift to reflect the TSOs' requirement for operational reserve. Our understanding has been that the TSOs will take demand control actions and seek to retain more than 100MW of minimum operational reserve. This must be reflective of actual practice and not a theoretical minimum reserve margin.

Of the options presented in paragraph 4.3.9, we are surprised that none reflects the combination as set out in paragraph 4.3.7 reflecting an improved and aligned security standard of 3 hour LOLE and an additional uplift to reflect the buffer margin at which the TSOs will enact demand control. This is quoted to be equivalent to 350MW although we believe the buffer margin for operating reserve should actually be greater than 100MW and hence the overall increase should be 400-450MW.

In addition, there is a current minimum spinning reserve requirement that has locational minimums for NI and RoI. This requirement indicates that there is a locational element to the operating margin and this has been the practice over many years. This minimum locational operational reserve must therefore be added to the minimum capacity requirement determined as being the minimum needed to satisfy the Locational Constraints.

Chapter 5. <u>Administered Scarcity Pricing Parameters</u>

Q1: Which of the options for the value of Full ASP do you consider most appropriate for the first T-4 capacity auction, and why?

A key point is that the I-SEM ASP is a price floor and that prices can rise above those prices. That opportunity means that alignment with GB is less important and I-SEM prices can rise to GB levels and therefore would avoid distortionary energy flows that could arise if one region's prices were capped at a lower level than the other.

The other concern is that if ASP were to rise then the financial element of the RO becomes a larger risk for participants to manage. However, the functioning of the secondary capacity market in I-SEM is uncertain. If there is limited liquidity then participants will have no tools to manage their risks during outages. As the I-SEM has yet to commence there is no indication as to how this secondary market will develop and hence an increase to the ASP would increase the financial risk with no clarity as to whether the risk could be managed.

We also note that there are no firm proposals for higher price caps in the DAM/IDM/BM. On the basis that harmonisation is not necessary and that there is no experience of the secondary market to facilitate risk management, we would therefore suggest that there should be no change to the value of the Full ASP at this time. Hence we consider Option A to be the most appropriate.

Q2: Should we move to setting VoLL on an October to September year, rather than the current Calendar Year basis, so that a single value of VoLL pertains within a Capacity Year?

PPB agrees that it would be sensible to set VoLL on a tariff/ capacity year basis.

Chapter 6. <u>Auction Volumes and Demand Curve</u>

Q1: Should the proportion of the CR the SEM Committee hold back from the T-4 CY2022/23 auction for the T-1 CY2022/23 be increased from 5% to 7.5%, and why?

PPB does not agree that the proportion of the Capacity Requirement (CR) held back from the T-4 auction should increase. 5% of the CR is the equivalent of c350MW which is broadly a CCGT unit and withholding this demand will both distort the price and may send inappropriate closure signals.

Reducing the CR but requiring generators to participate will have the consequence of artificially reducing the clearing price relative to what is would be if the full CR were used which is clearly a concern since the capacity price in T-4 auctions will always be under-valued.

Further, it will send closure signals to conventional capacity who are required to provide 3 years notice of closure and would have to make investment decisions with regard to maintenance in the period prior to a T-1 auction that it had no certainty over. Hence such generators will be unlikely to commit new investment against the high level of risk of not obtaining a contract at the T-1 stage.

This will further distort the market by reducing the capacity capable of competing in the T-1 auctions, with a large proportion likely to be DSU capacity, and the lack of competition will tend to put upward pressure on prices in the T-1 auctions in contrast to the price depression that will occur in the T-4 auctions. Further while DSU capacity is important, it has a high energy price which at low volumes is less material, but which becomes more material to the overall costs for customers as the volume of capacity increases.

There is therefore a high risk that holding back any capacity from the T-4 auction will result in an inefficient plant mix that will not be the least cost outcome for customers.

Increasing the amount held back to 7.5% will just serve to make the outcomes more distorted and ultimately less competitive by artificially depressing the prices in the T-4 auctions even further, sending stronger closure signals that may not be efficient and potentially creating un-competitive T-1 auctions.

For these reasons, PPB does not support greater withheld capacity and would suggest that the decision to withhold any capacity should be re-considered.

Q2: ***Should the minimum MW in each constrained area be adjusted for volumes withheld from the T-4 auction to the T-1 auction for CY2022/23? Which of Options 1, 2 and 3 do you prefer, and why?***

In line with our response to the previous question, withholding capacity from a T-4 auction will distort the pricing and send erroneous closure signals to capacity that may actually be required. This may be even more critical in relation to constrained areas where the options to resolve those constraints in the T-1 timeframe may be even more limited and therefore the risk of inefficient outcomes is even greater.

PPB considers Option 1 will provide the most efficient outcome.

Q3: ***Which of the demand curve options, Options A or B, in your view is the most appropriate for the first T-4 capacity auction, and why?***

It is difficult to comment on Option B as the curve is not defined but merely shown as a line on Figure 9. There is no rationale to justify and define the start and end points of the line or whether the line is just arbitrarily selected.

PPB sees no reason that justifies a change from the current demand curve and hence we consider Option A to be the most appropriate.

Chapter 7. *T-4 Auction Price Caps For Capacity Year 2022/23*

Q1: ***Do you agree with the proposal to keep the Auction Price Cap (APC) at 1.5 x Net CONE for the T-4 auctions? If not, please explain. Is your response in any way contingent upon the final value of BNE Net CONE for CY2022/23?***

There is greater uncertainty in a T-4 auction than in a T-1 auction which a bidder must take into account when assessing and formulating bids. For example, as noted in the consultation paper in footnote 39, the ASP cannot be guaranteed as they could be impacted by EU harmonisation changes which could have a significant impact on payments to be made under the RO. Similarly, revenue streams are more uncertain giving the demand profile may change, I/C flows may vary due to plant mix changes in the interconnected region, DS3 tariffs may change, other costs such as Gas Transportation can vary significantly (as evident from a near 30% increase in NI capacity charges for 2018/19 relative to what the GMO and Regulator indicated 10 months ago).

Given this increased level of uncertainty, there is a good case for having a factor higher than 1.5 for T-4 auctions to reflect the greater uncertainty.

The BNE Net Cone calculation does impact on this since where that conversion from “Gross” to “Net” has IMR deductions, DS3 deductions based on existing tariffs etc, then those estimates, as noted above, are subject to volatility and change and hence a higher margin is required to cover that increased risk.

Q2: Do you agree with the proposal to keep ECPC at 0.5 x Net CONE for the T-4 auctions? If not, please explain. Is your response in any way contingent upon the final value of BNE Net CONE for CY2022/23?

In the same manner as we outline in our response to the previous question, there is greater uncertainty in a T-4 timeframe for both costs and revenues for an existing generator.

We have particular concerns over the financial element of the RO which a capacity holder must pay out when market prices exceed the RO Strike Price. These payments must be estimated and the risk of not being scheduled at the time they occur priced in to the bid. This cost and risk is not properly reflected in the BNE Net CONE and it is wholly inappropriate in the ECPC where this is set at 50% of Net CONE.

The capping at 50% also creates a volatile clearing price whereby prices (barring USPC) are capped at 50% Net CONE only rising above it in a year where New Entry occurs and dropping back to 50% until the next new entry. This profile is very spikey and does not follow price tracks that would normally be expected to increase on the lead up to new entry.

We therefore consider that the ECPC should be higher than 50% of Net CONE to reflect both the incorrect pricing and the uncertainty of the RO payments, as well as more general uncertainty of costs and revenues on a T-4 timeframe.

As for the APC, the final value of the BNE Net CONE for CY2022/23 will affect the margin required and a low ECPC will result in more USPC applications which adds a further degree of uncertainty and opaqueness to the auction process.

Q3: USPC setting: Do you agree with the proposed approach for UFI submissions?

PPB has been disallowed from applying for a USPC and hence cannot avail of the process. However PPB would still be affected by the USPC’s of other generators and hence the process must allow for all elements of a generator’s costs and must not be artificially curtailed to mean that generation is capped at a price that is lower than its costs and hence would in effect be operating at a loss. As we stated in previous consultations, the NGFC must also include financing costs (e.g. to service debt costs) which are legitimate costs of operating in the market.

There is also an issue around shared costs that is a problem when there are multiple units on a site. Those common costs are normally allocated across all units on the site but if some of the units do not secure a contract and close down as per the signal then the shared cost allocation to the remaining units would increase. The USPC should provide for multiple contingent values depending on which units secure a contract. The capacity auction should also reflect the correct underlying cost allocation for that unit dependent on the combination of successful units at the site.

The final issue is the greater cost and revenue uncertainty in a T-4 auction and similar to our comments on the APC and ECPC, a margin greater than 10% would be required to reflect the increased risk. For example, we have highlighted that there have been significant short notice changes in regulated tariffs over the last few years (NI Gas Transportation capacity charges increasing by 30%, NI GTUoS charges increased by c40% in Oct 2017) which clearly illustrates the risk over 1 year in regulated charges that should be more predictable, never mind the scope for change over a 4-5 year horizon.

Q4: USPC setting: Do you agree with the proposal to apply 2% p.a. inflation projection for estimating costs for CY 2022/23?

We do not agree that the application of 2% p.a. inflation is appropriate. Inflation is currently running in excess of 3% and the impact of Brexit will likely impact on inflation being higher than the long term target of 2%. We would suggest 3% p.a. may be a more appropriate projection.

Chapter 8. <u>Derating Factors</u>

Q1: Do you have any views on the proposal of EMDF value of 60% subject to review and update of the analysis for the decision paper?

In relation to the proposed EMDF we note the comment in paragraph 5.2.5 that "*At times of scarcity, under current European codes, TSOs have the ability to reduce exports*". Given this right then it would be unwise to rely on a source of supply in times of capacity shortage that can be unilaterally withdrawn by the external TSO. This would suggest that customers would be better served by relying on indigenous capacity that, while subject to normal outage risk is not capable of being withdrawn by a 3rd party at their discretion. Hence we consider the I/Cs should be de-rated even further.

Q2: Do you expect to be applying to qualify a new interconnector between the I-SEM and an external market other than GB?

Not Applicable.

Q3: Do you have any feedback on the issues around transitioning from the interim to the hybrid solution for cross-border trading of capacity?

There is clearly significant uncertainty over the enduring treatment of cross-border capacity and External CMUs. The need to exclude capacity that is already subject to other support mechanisms (e.g. ROC and FiT contracts in GB), represents a difficult administrative challenge. It also highlights that significantly more thought is needed on the legal arrangements to which external CMUs must comply with. For example in addition to signing up to the Capacity Market Code (CMC) and Trading and Settlement Code (TSC), do those external units also require a licence to participate and, if not, what remedies exist to enforce compliance with their obligations under the CMC and TSC?

Once the market moves to the enduring arrangement, we reject the proposal set out in paragraph 8.1.26 that "*unused de-rated interconnector capacity might sensibly be used to adjust the demand curve*". If external capacity is unable to commit to the I-SEM then that implies there is a limit to what is available. Adjusting the demand curve in the "hope" that there might be capacity available represents the SEMC taking a gamble and assuming they know better than the market. This is a dangerous proposition and at odds with a market driven approach.

The proposals in paragraphs 8.1.28 through to 8.1.32 are speculative and there is little merit in considering them until the precise detail of the detailed design of the hybrid solution is known. Our suggestion would be to keep it simple over the transition and avoid creating multiple prices and carving up already cleared capacity as such mechanisms will only add confusion and complexity in what is an already complex area. Consideration must also be given to any impacts that any re-auctioning would have on the secondary market including any impact on liquidity in what will likely be an illiquid market in the early stages.

Chapter 9. New Capacity Investment Rate Threshold

Q1: Do you agree with keeping NCIRT at €300/kW, in the light of new evidence on BNE gross investment costs? Does your view depend on the choice of BNE reference plant resulting from the Best New Entrant consultation (SEM-18-025)?

PPB is not responsible for investment and others will be better placed to provide comment on this topic.

Chapter 10. ***<u>Summary of Parameters</u>***

Q1: ***Do you have any comments on any of the parameter summarised in Table 6, which are not already covered in your responses to other consultation questions?***

We have nothing further to add to our comments already made above.